# CHIEFTAIN INTERNATIONAL, INC.

## 2000 ANNUAL REPORT

EXPLORING

TO CREATE

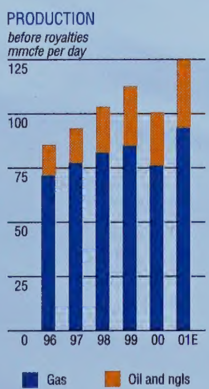
VALUE

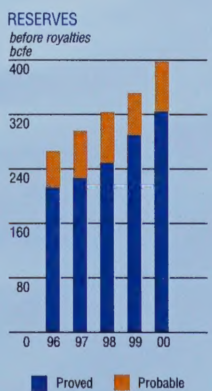
## CONTENTS

# HIGHLIGHTS

| Year ended December 31, *(in thousands except per share amounts)* | US$ 2000 | US$ 1999 | C$ 2000 | C$ 1999 |
|---|---|---|---|---|
| **FINANCIAL** | | | | |
| Production revenue, before royalties | **$ 142,391** | $ 91,507 | **$ 213,615** | $ 132,072 |
| Cash flow from operations, after preferred share dividends | **93,631** | 50,098 | **140,465** | 72,306 |
| Per common share - basic | **5.79** | 3.66 | **8.69** | 5.28 |
| - diluted | **4.99** | 3.22 | **7.49** | 4.65 |
| Net income (loss) | **27,348** | (11,839) | **41,027** | (17,087) |
| Per common share - basic | **1.69** | (0.86) | **2.54** | (1.24) |
| - diluted | **1.64** | (0.86) | **2.46** | (1.24) |
| Proved reserve value, PV 10% using constant dollars, before income taxes | **1,226,959** | 266,474 | **1,840,684** | 384,602 |
| Capital expenditures | **102,891** | 55,069 | **154,357** | 79,481 |
| Long-term debt | **20,000** | 10,000 | **30,004** | 14,433 |
| Working capital | **$ 9,962** | $ 13,604 | **$ 14,945** | $ 19,635 |
| Weighted average common shares outstanding - basic | **16,183** | 13,701 | **16,183** | 13,701 |
| - diluted | **19,745** | 13,701 | **19,745** | 13,701 |
| **OPERATING** | | | | |
| Average production rate, before royalties | | | | |
| Natural gas *(mmcf per day)* | **76.4** | 85.3 | | |
| Oil and ngls *(barrels per day)* | **4,022** | 4,611 | | |
| Equivalent *(mmcfe per day)* | **100.5** | 112.9 | | |
| Proved reserve volumes, before royalties | | | | |
| Natural gas *(bcf)* | **233.8** | 186.3 | | |
| Oil and ngls *(millions of barrels)* | **15.3** | 17.3 | | |
| Equivalent *(bcfe)* | **325.8** | 290.3 | | |
| US Gulf of Mexico offshore blocks | **152** | 139 | | |
| Wells drilled | | | | |
| Gross | **35** | 20 | | |
| Net | **13.2** | 7.3 | | |
| Success rate | **63 %** | 70 % | | |

Chieftain reports financial information in US currency. For convenience, Canadian dollar equivalents are provided using exchange rates at December 31, 2000 and 1999.



HIGHLIGHTS

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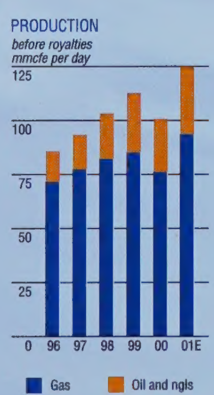
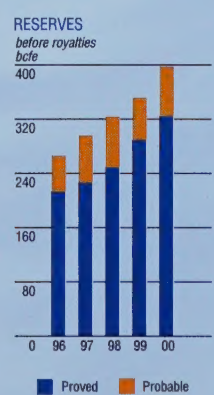


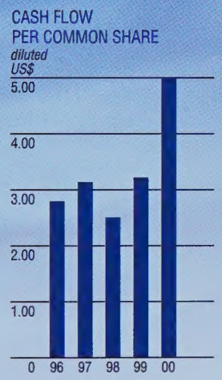
## CORPORATE PROFILE

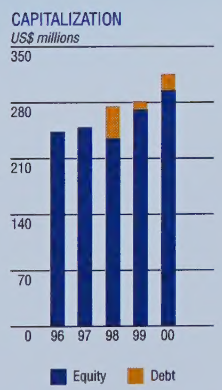
**Chieftain International, Inc.**, an independent natural gas and oil exploration and production company, is exploring to create value, focusing on the US Gulf of Mexico region. During 2000, Chieftain brought eight discoveries to production with a like number under development for production in 2001. Chieftain's exploration and development program includes a broad portfolio of geological targets including deeper and larger prospects.

Chieftain's head office is in Edmonton, Canada and exploration offices are in Dallas and New Orleans. The common shares are traded on the Toronto Stock Exchange and the American Stock Exchange under the symbol "CID". Preferred shares of Chieftain International Funding Corp., a wholly-owned subsidiary of Chieftain International, Inc., are traded on the American Stock Exchange under the symbol "GSS.PR".

This Annual Report contains forward-looking statements that are subject to risk factors associated with the oil and gas business. The Company believes that the expectations reflected in these statements are reasonable, but may be affected by a variety of factors including, but not limited to: price fluctuations, currency fluctuations, drilling and production results, imprecision of reserve estimates, loss of market, industry competition, environmental risks, political risks and capital restrictions.

## PRESIDENT'S MESSAGE




We entered the year 2000 confident that we were well positioned for the future. That confidence proved to be well founded as we recorded the best year in our corporate history. Our technical expertise, innovative ideas and financial strength combined with increased commodity prices to produce strong results financially and operationally.

Financially, 2000 brought record results. Production revenue increased 56% to \$142.4 million (C\$213.6 million). Cash flow from operations, after preferred dividends, was up 87% to \$93.6 million (C\$140.5 million). On a per share basis, cash flow was \$5.79 (C\$8.69) basic or \$4.99 (C\$7.49) diluted. Net income improved by \$39.2 million to \$27.3 million (C\$41.0 million). Net income per share was \$1.69 (C\$2.54) basic or \$1.64 (C\$2.46) diluted. Our long-term debt increased modestly to \$20 million (C\$30 million), equivalent to less than three months of 2000 cash flow from operations, and our debt to equity ratio remained one of the best in the industry at six percent.

Chieftain's reserve growth continues. During 2000 our total proved reserves increased by 12%, after production, and our reserve replacement rate was 197%. For the seventh consecutive year, reserve additions exceeded production.

The estimated present value of our proved reserves at year-end, using constant year-end prices and costs and a 10% discount rate, all in accordance with US Securities and Exchange Commission guidelines, reached \$1.2 billion (C\$1.8 billion), almost a five-fold increase over the 1999 year-end value. Including probable reserves, the value was \$1.5 billion (C\$2.2 billion). The year-end prices required to be used for this valuation were: for the United States, \$9.68 per mcf for natural gas and \$24.60 per barrel for oil and ngls; and for the UK, \$3.65 per mcf for natural gas. If reserve values were based on average composite prices received in the month of December, 2000 of \$6.05 per mcf and \$27.49 per barrel, the resulting value of our proved reserves would have been \$866 million (C\$1.3 billion). The value of our proved and probable reserves would have been \$1.1 billion (C\$1.6 billion) on the same basis.

Adding to Chieftain's value is our extensive exploration acreage in the US Gulf of Mexico region. The acreage contains a large inventory of undrilled prospects, which increase in value with increasing commodity prices. Today we have interests in 152 offshore US Gulf of Mexico lease blocks, up from 139 at the end of 1999.

In 2000, capital spending was \$102.9 million (C\$154.4 million), including \$36.9 million (C\$55.4 million) of development expenditures used to place new production on stream. We participated in the drilling of 35 wells in the US Gulf of Mexico region, achieving a 63% success rate, and brought eight natural gas discoveries to production.

Since Chieftain's inception, we have endeavored to keep the number of common shares to a minimum, so that the impact of success could be significant to our shareholders. The number of common shares issued and outstanding at year-end was 16,100,827 or 19,662,867 shares on a diluted basis. During the second half of 2000, we announced a normal course issuer bid to repurchase up to 1,000,000 common shares. As at December 31, 2000, we had repurchased and cancelled 228,600 common shares for a total of $4.9 million (C$7.3 million)

## OUTLOOK

Our strategy for growth is focused on drilling and developing our extensive exploratory prospects in the US Gulf of Mexico region. While we will continue to be primarily active in the shallower waters of the Continental Shelf, we are building our exposure to the deeper waters of the Gulf. We anticipate drilling 36 wells in the year 2001, of which 7 will be deeper wells on the Continental Shelf and 3 will be deep-water prospects. We expect to develop eight areas for new production in 2001. Our capital expenditures budget for the year, set at $105 million (C$158 million), may vary, depending upon opportunities.

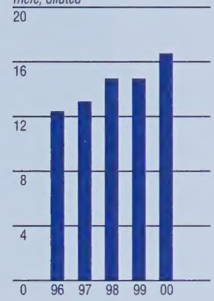
We are projecting a 24% increase in 2001 production to an average of 125 million cubic feet equivalent per day, of which approximately 75% will be natural gas and the balance oil and ngls. Further, we expect that our average natural gas price in 2001 will exceed the 2000 average and that our average oil price will be stable and in line with our average for 2000. If these estimates are correct, we can expect substantially stronger cash flow from operations for the year 2001. At these price levels, cash flow would exceed our budgeted capital expenditures by a significant margin, allowing Chieftain to maintain its disciplined approach to balance sheet management and remain financially strong.

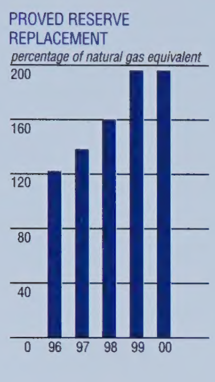
Our optimism for the coming year is based on our proven technical expertise, our large land holdings in the US Gulf of Mexico and the increasing demand for natural gas in all areas, particularly for gas-fired electrical generation.

On behalf of the Board, let me thank our shareholders for their continued support and our employees for their conscientious efforts to enhance shareholder value.

Stanley A. Milner, A.O.E., LL.D.
President and Chief Executive Officer
February 12, 2001

PROVED RESERVES
PER COMMON SHARE
*before royalties*
*mcfe, diluted*





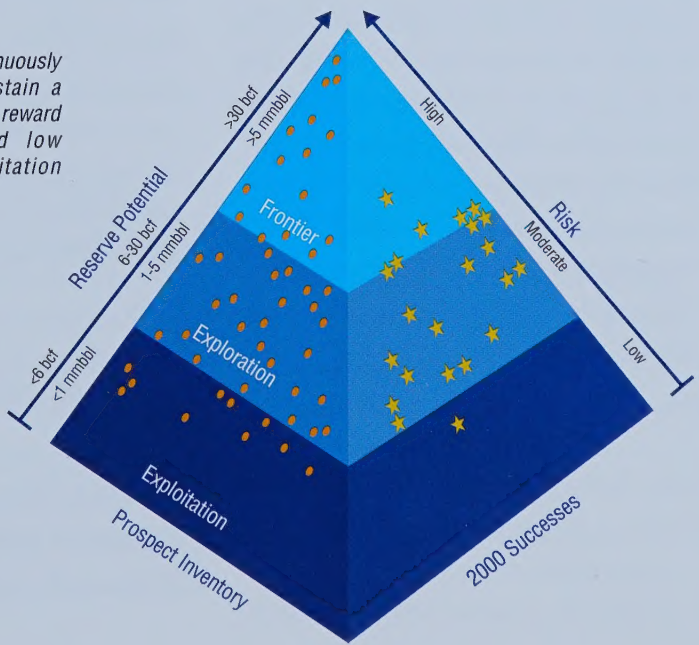

## OVERVIEW

Our 2000 exploration and development program, conducted primarily in the US Gulf of Mexico region, was our largest to date. When the year began, we planned to drill 27 wells, develop 6 new fields and spend approximately $86 million in the region. As the year progressed, we responded to opportunities which expanded our drilling program to 35 wells, almost twice the number drilled in 1999, and brought 8 discoveries to production. Capital expenditures for the year were $102.9 million. Successful drilling has added eight new fields that will be developed in 2001. For the seventh consecutive year, we increased our reserves and more than replaced our production. At year-end our natural gas equivalent production had grown to 122 mmcfe per day.

Since the beginning of 2000, higher commodity prices have stimulated industry activity, contributing to increased costs and heightened competition for good quality exploration prospects. As a prospect generator and operator, we can, to a degree, minimize the effects of competition and higher costs by controlling the timing of projects and investing prudently. During 2000, we were operator of nine wells, almost twice as many as in 1999. Our technical people, with an average of more than 20 years experience, continually generate and evaluate drilling prospects on our extensive US Gulf of Mexico undeveloped acreage, maintaining and building our prospect inventory across the risk continuum from the exploitation of recent discoveries to the drilling of high impact deep-water exploration plays. During the

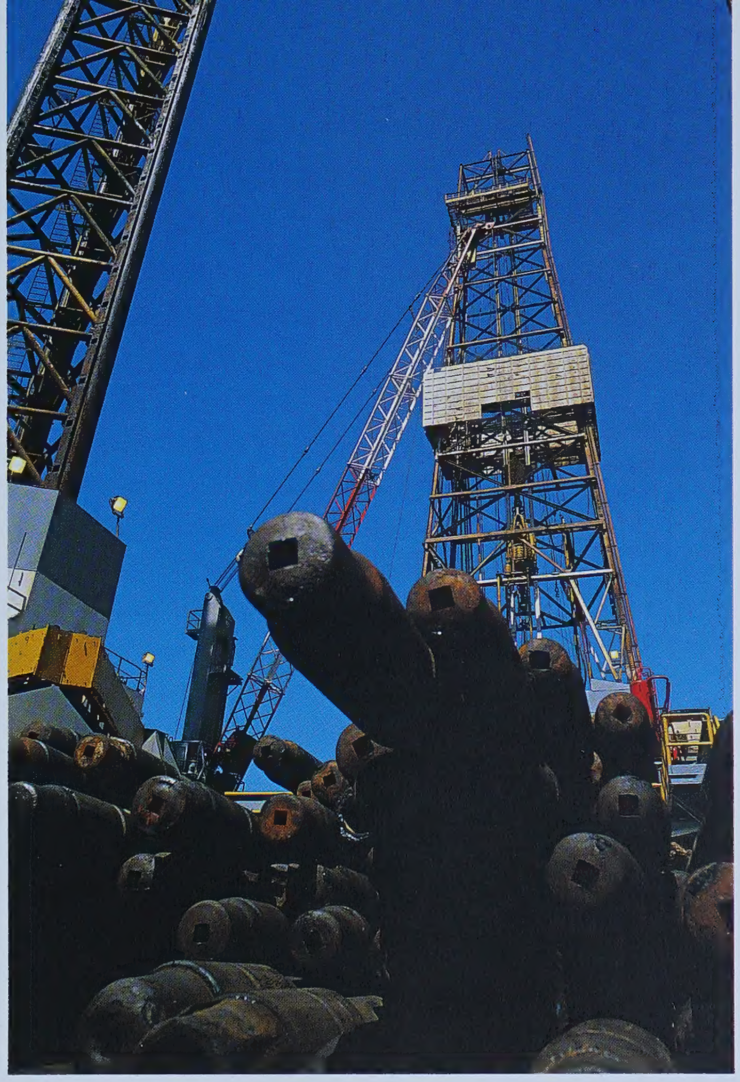
### Prospect Inventory

*The prospect inventory is continuously upgraded and aligned to sustain a balance between high risk/high reward exploration prospects and low risk/moderate reward exploitation projects.*



last four years, this talented group achieved a 65% success rate in the drilling of 99 wells in the US Gulf of Mexico region.

During 2000, a total of eight significant sources of new production were brought on stream, bringing our 2000 exit rate of natural gas equivalent production to 122 million cubic feet per day. During the early part of 2000, production output decreased from the prior year, as natural declines in existing fields were not offset by new production. The majority of the fields discovered in 1999 and scheduled for development in 2000 experienced delays in follow-up drilling and in facilities design and installation. The decline in production was halted during the second quarter and growth resumed during the balance of the year.



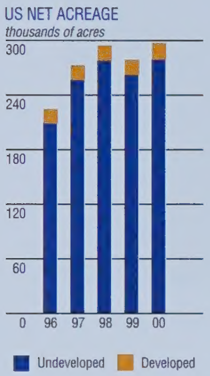
*Our 2000 drilling program included a record 35 wells in the US Gulf of Mexico region of which 22 were successful.*

Building on our past success, we are budgeting capital expenditures of $105 million in 2001, with approximately 60% allocated to exploration spending and the balance to development. Our US Gulf of Mexico exploratory drilling program can be described as falling into three subsets of exploration targets. One category is comprised of traditional shallow to medium depth wells of up to 15,000 feet in relatively shallow water depths of up to 600 feet on the Continental Shelf. Increasingly, however, our efforts have been directed at targets offering greater potential. These targets fall within two exploration types: deeper wells drilled to more than 15,000 feet on the Continental Shelf and wells in water depths of more than 600 feet. The higher risk/higher reward targets of these prospect types are multiple pay zones which typically yield significant production volumes.

We have identified three deep-water wells for drilling in 2001. Two of the three are located near existing production infrastructure. Based on our risk assessments, we have limited our working interests to an average of approximately 25%, a level which provides significant but manageable exposure to potentially sizeable new natural gas and oil fields.

Development projects planned for 2001 include eight new natural gas and oil fields where production facilities will be

installed. All of these fields are expected to be producing before year-end. In most cases, wells have been completed and facilities have been purchased or are being constructed. This will enable us to capture the higher commodity prices prevailing in the market. Our ongoing drilling program offers potential for further additions to our inventory of development projects. We are the operator of almost half of our current development projects, affording us better control of schedules and expenditures.




## LEASE HOLDINGS

Undeveloped lease acreage is the foundation for growth in our business. The majority of our leases are undeveloped and many contain identified, drillable geological prospects. During the year, we increased our holdings of offshore lease blocks to 152 from 139 at the end of 1999. Chieftain is one of the top 10 independent leaseholders in the US Gulf of Mexico. At the two US Federal Government offshore lease sales in 2000, Chieftain and its partners acquired 14 blocks for a total consideration, net to Chieftain, of $4.3 million. At December 31, 2000, we had an average working interest of 40% in 152 blocks, covering 719,798 gross acres (285,598 net acres) offshore in the US Gulf of Mexico. The offshore lease inventory includes 99 undeveloped and 53 producing blocks. At year-end, onshore US lease holdings were 41,219 gross acres (11,593 net acres), bringing total US holdings to 761,017 gross acres (297,191 net acres). Overseas, we hold production licenses on 46,553 gross acres (8,272 net acres) in the UK sector of the North Sea.

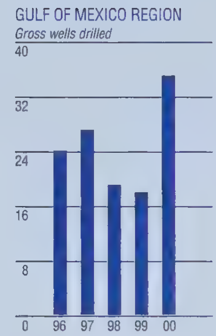
| **Natural Gas and Oil Rights** | Acres | |
|---|---|---|
| Location | Gross | Net |
| Offshore US Gulf of Mexico | | |
| Louisiana (72 blocks) | 321,469 | 119,787 |
| Texas (69 blocks) | 334,969 | 147,187 |
| Deep water (11 blocks) | 63,360 | 18,624 |
| | 719,798 | 285,598 |
| Onshore US | | |
| Utah | 30,980 | 5,626 |
| Louisiana | 4,558 | 2,276 |
| Other | 5,681 | 3,691 |
| | 41,219 | 11,593 |
| Total US | 761,017 | 297,191 |
| UK North Sea | 46,553 | 8,272 |
| Total | 807,570 | 305,463 |

## DRILLING RESULTS

Our drilling activity in the US Gulf of Mexico region increased significantly in 2000. Chieftain drilled 35 wells (32 exploratory and 3 development) in the region, almost twice the number drilled in 1999. Included were 32 wells offshore and 3 onshore, of which 22 were commercial natural gas wells, for an overall success rate of 63%. Successful drilling in 2000 included 19 exploration discoveries, of which 17 were offshore and 2 were onshore in Louisiana. Discoveries in the offshore were on East Cameron 83, East Cameron 104 (2 wells), High Island A-467, High Island A-554, Matagorda Island 704, South Pass 38, South Timbalier 250, Vermilion 267 (2 wells) and West Cameron 192, 300, 370 (4 wells) and 614. Onshore in Louisiana, exploration discoveries were made at Chacahoula and in the Northeast Wright area at Delahoussaye. Following up earlier exploration successes, development wells were drilled at High Island A-531, Matagorda Island 704 and onshore at Langlinais in the Northeast Wright Field.

Chieftain added 72.4 bcfe of natural gas equivalent reserves during 2000, replacing 197% (185% after royalties) of 2000 production. Total proved reserves, after production, increased 12% to 326 bcfe (266 bcfe after royalties) and total proved plus probable reserves increased 13% to 398 bcfe (324 bcfe after royalties).

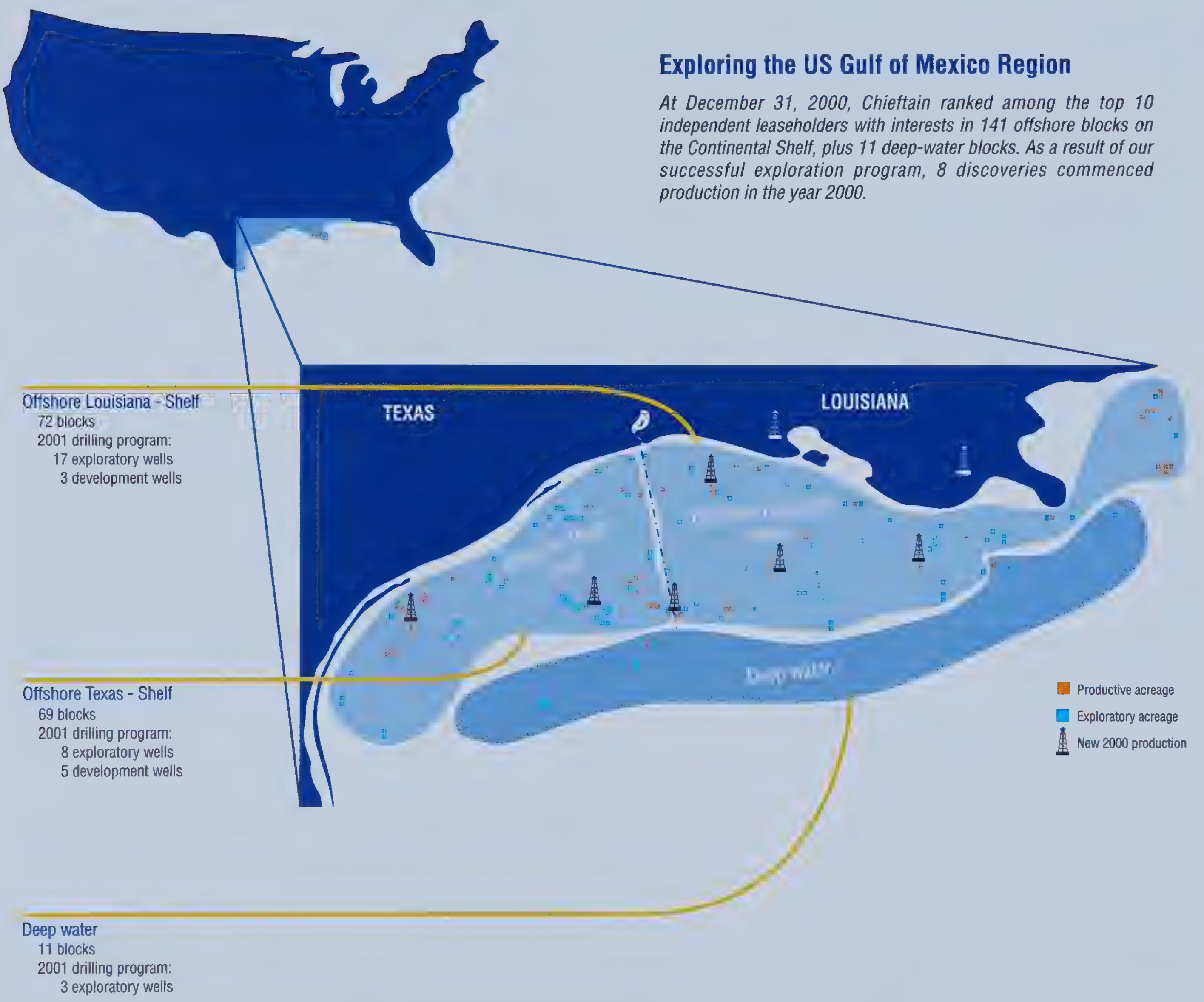
Estimates of our reserves are prepared in accordance with US Securities and Exchange Commission guidelines, which require the use of constant year-end prices and costs. Chieftain's US reserves, comprising 98% of total reserves, were evaluated by Netherland, Sewell & Associates, Inc., independent petroleum engineers, and were reviewed by the Reserve Committee of the Company's Board of Directors. All committee members are independent directors of Chieftain. The remaining two percent of total reserves, located in the UK sector of the North Sea, were evaluated internally.




| 2000 Drilling Results | Exploration | | Development | | Total | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Natural gas | 19 | 7.13 | 3 | 1.25 | 22 | 8.38 |
| Dry | 13 | 4.80 | – | – | 13 | 4.80 |
| Total wells | 32 | 11.93 | 3 | 1.25 | 35 | 13.18 |

## Exploring the US Gulf of Mexico Region

*At December 31, 2000, Chieftain ranked among the top 10 independent leaseholders with interests in 141 offshore blocks on the Continental Shelf, plus 11 deep-water blocks. As a result of our successful exploration program, 8 discoveries commenced production in the year 2000.*



## FIELD DEVELOPMENT

During 2000, we participated in developing eight discoveries that added significant natural gas and oil production. These included offshore fields at High Island A-530, Matagorda Island 704, South Timbalier 196, Vermilion 267, West Cameron 300 and West Cameron 613/614 and expansion of onshore facilities at Chacahoula and Northeast Wright in Louisiana. By year-end, our share of production from these new fields was approximately 50 mmcfe per day before royalties.

Successful exploration activity has brought the number of 2001 development projects to eight. Engineering design work, construction and/or installation of production facilities is proceeding for offshore blocks East Cameron 83, East Cameron 104, Eugene Island 189, High Island A-510/A-531, High Island A-554, South Timbalier 250 and West Cameron 370. A discovery on High Island A-467 required minimal development, having been drilled from an existing production platform.

*During 2000, we brought eight discoveries to production with a like number under development for production in 2001.*

## OFFSHORE LOUISIANA

**East Cameron Area:** Chieftain holds working interests averaging 34.6% in 7 blocks covering 32,500 gross acres (11,250 net acres). At East Cameron 83 (25% working interest) we participated in a multi-zone discovery on a deep natural gas trend, located in 40 feet of water. Facility design and construction is under way with first production scheduled for mid-2001. Additional drilling will follow when the production facility is in place. At East Cameron 104 (40% working interest), two natural gas exploratory wells were successful. A production facility has been purchased and is being refurbished for installation during the second quarter of 2001 with first production expected by mid-year.

**West Cameron Area:** This was our most active drilling area during 2000. Nine exploratory wells were drilled, accounting for approximately one-quarter of our 2000 program, resulting in seven new discoveries. At West Cameron 300 (35% working interest), which is Chieftain-operated, two wells were drilled, resulting in one discovery. An unmanned production facility was installed and production

*We are continuing an active drilling program in the US Gulf of Mexico with 36 wells planned for 2001.*

commenced during the fourth quarter of 2000. During the first quarter of 2001, a third well, drilled to test natural gas potential in a deeper zone, resulted in a discovery. At West Cameron 614 (25% working interest), we drilled a well to approximately 13,600 feet, encountering 75 feet of natural gas pay thickness in Pleistocene sands. The well was completed and tied-in to the production platform on West Cameron 613 (25% working interest) where a successful natural gas well was drilled in 1999. Initial production from both blocks commenced in December 2000. On West Cameron 370 (40% working interest), which was acquired at the US Federal Government Central Gulf lease sale in March 2000, four successful natural gas wells were drilled and completed for production. A platform has been acquired and production is expected to commence in the first half of 2001. Two other prospects have been identified for possible drilling after production from the discovery wells begins. At West Cameron 192 (25% working interest), a multi-zone natural gas discovery was drilled to approximately 10,800 feet from an existing production facility and commenced production before year-end. Locations for two additional development wells have been identified on the block and are included in our drilling plans for 2001. Our drilling plans for 2001 also include an exploratory well at West Cameron 135 (50% working interest), which is considered part of the deeper natural gas trend on the Continental Shelf.

## OFFSHORE TEXAS

**High Island Area:** During 2000 we drilled five exploratory wells and one development well in the High Island area. Successful wells were drilled on High Island A-467, A-531 and A-554. The High Island A-467 exploratory well (50% working interest) was drilled from an existing production facility in December 2000 to a total depth of 8,500 feet and encountered Miocene sands. Minimal development work on the well was required and production commenced early in 2001. At High Island A-531 (50% working interest), a property we operate, a development well was drilled to follow up our original 1999 natural gas and oil discovery. An unmanned production platform has been fabricated and

installed on High Island A-510 to handle production from both leases. A third well, drilled early in 2001, has been completed and production from the field is expected to commence during the first half of 2001. At High Island A-554 (41.7% working interest), a Chieftain operated property, a successful natural gas exploratory well was drilled to a depth of 6,000 feet. Work on facility design is under way and natural gas production is projected to commence during the fourth quarter of 2001.

The 1999 High Island A-530 discovery (75% working interest), which is Chieftain operated, commenced production in December 2000 from an unmanned production facility installed during the year.

## DEEP WATER

We currently have interests in 11 deep-water exploration blocks in the US Gulf of Mexico. Our technical team has identified several prospects where the discovery of large reservoirs could have a significant impact on Chieftain. Exploratory wells are planned for three deep-water locations, including natural gas and oil prospects at Mississippi Canyon 29, Mississippi Canyon 489/490 and Garden Banks 397/441. At Mississippi Canyon 29 (27% working interest), the "Schellhorn Prospect" is the target of a directional well to be drilled from the BP Oil Ltd.-operated Pompano subsea template. The well will test 3D seismically identified objectives at vertical depths ranging from 10,000 to 12,000 feet. If the well is successful, the Pompano facility would handle the production, which could commence in 2001. Although the well has the attributes of a deep-water well in terms of potential reservoir size and flow rates, its costs are more closely associated with those of wells located on the Continental Shelf because infrastructure is in place. Mississippi Canyon 489 (20% working interest) was acquired at the March 2000 US Federal Central Gulf of Mexico lease sale. Using state-of-the-art 3D seismic, a potential natural gas prospect has been identified in water depths of 1,600 to 1,800 feet and will be drilled during the first half of 2001. Should the well be successful, it can be tied-in

*Our 2001 drilling program includes three deep-water exploratory wells which have the potential to add significant value to Chieftain.*

*In 2000, we replaced 197% of production, largely through the drill bit, increasing our reserves for the seventh consecutive year.*

quickly to readily accessible pipeline infrastructure. The Garden Banks 397/441 (25% working interest) "Antigua" prospect appears to represent a classic geological model of an oil bearing trap below a subsalt canopy. Based on 3D seismic interpretations, there is potential for thick oil bearing reservoirs under the salt sheet. The block is located in approximately 2,500 feet of water and plans are to drill an 18,000-foot well during 2001. The potential dry hole cost of the three-well deep-water drilling program, net to Chieftain, is less than 12% of our approved capital budget for 2001.

## OTHER

Chieftain has interests in several other producing properties including the light oil producing Aneth and Ratherford Units in Utah (13.4% and 21.4% working interest, respectively), the Chacahoula and Northeast Wright Fields (50% working interest) in Louisiana and the Galahad and Mordred fields (17.8% and 5.3% working interest, respectively) located in the UK sector of the North Sea. At Aneth, a carbon dioxide-injection enhanced recovery pilot project is under way. At the Northeast Wright Field, in Louisiana, plans include the drilling of another development well and the workover of the Broussard #1 well to stimulate natural gas production. We have no present plans for further capital expenditures on our UK holdings, which produced an average of 5.4 mmcfe per day, royalty free, net to Chieftain, during 2000.

# MANAGEMENT'S DISCUSSION AND ANALYSIS

*You should read the following discussion and analysis in conjunction with our 2000 audited consolidated financial statements. The information contains forward-looking statements that are subject to risk factors associated with the oil and gas business. Forward-looking statements typically contain words such as "anticipate", "believe", "expect", "plan" or similar words suggesting future outcomes. We believe that the expectations reflected in these statements are reasonable, but may be affected by a variety of factors including, but not limited to: price and currency fluctuations, drilling and production results, imprecision of reserve estimates, loss of market, industry competition, environmental risks, political risks and capital restrictions.*

*Our financial statements and information are reported in US dollars and are prepared based upon Canadian generally accepted accounting principles. Substantially all of our revenues and a significant portion of our operating expenses are realized or incurred in US dollars. For a discussion of the effect of differences in generally accepted accounting principles in Canada and the US on our financial statements, see Note 12 to our audited consolidated financial statements. For purposes of calculating unit costs, oil and ngls are converted to mcf equivalents at the rate of one barrel of oil per six thousand cubic feet of natural gas.*

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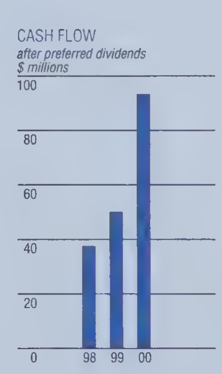
## 2000 OVERVIEW

Strong natural gas and oil prices contributed to our record financial results in 2000. Revenues were $145.3 million ($119.9 million after royalties), net income applicable to common shares was $27.3 million, and cash flow from operations, after preferred share dividends, was $93.6 million. These amounts compare to revenues of $92.6 million ($76.4 million after royalties) in 1999 and $77.6 million ($64.4 million after royalties) in 1998, losses applicable to common shares of $11.8 million in 1999 and $9.1 million in 1998 and cash flow from operations of $50.1 million in 1999 and $37.8 million in 1998.

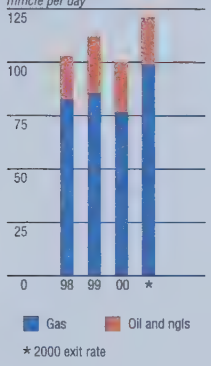



Basic net income per common share was $1.69 in 2000 compared to losses of $0.86 per share in 1999 and $0.67 per share in 1998. Basic cash flow from operations was $5.79 per share in 2000 compared to $3.66 per share in 1999 and $2.81 per share in 1998.

Our average natural gas price was $3.63 per mcf in 2000 compared to $2.02 per mcf in 1999 and $1.99 in 1998. Our combined average crude oil and ngls price was $27.72 per barrel in 2000 compared to $17.05 in 1999 and $11.74 in 1998.

Net capital spending was $102.9 million in 2000 compared to $55.1 million in 1999 and $92.7 million in 1998. Three year finding and development costs for proved reserves were $1.17 per mcfe ($1.50 per mcfe after royalties) in 2000 compared to $1.15 per mcfe ($1.45 per mcfe after royalties) in 1999 and $1.51 per mcfe ($1.89 per mcfe after royalties) in 1998.

PRODUCTION
*before royalties*
*mmcfe per day*




We increased our proved reserves for the seventh consecutive year, adding 72.4 bcfe (56.2 bcfe after royalties), a reserve replacement rate of 197% (185% after royalties). Total proved reserves increased to 326 bcfe (266 bcfe after royalties).

At December 31, 2000, our proved reserves had a present value of future net cash flows before income taxes, discounted at 10%, of $1.2 billion (1999 - $267 million; 1998 - $153 million). These values reflect the required use of year-end prices, which at December 31, 2000 were $9.68 per mcf for US natural gas and $24.60 per barrel of oil.

Production in 2000 averaged 100.5 mmcfe per day (82.9 mmcfe per day after royalties) compared to 112.9 mmcfe per day (93.4 mmcfe per day after royalties) in 1999 and 103.2 mmcfe per day (85.2 mmcfe per day after royalties) in 1998. New production from eight properties was added during 2000, primarily during the second half of the year. Production commenced from three of these properties in December. As a result of this additional production, our exit rate at December 31, 2000 was 121.6 mmcfe per day (99.5 mmcfe per day after royalties).

## PRODUCTION

| **Production Summary** | Before royalties | | | After royalties | | |
|---|---|---|---|---|---|---|
| | **2000** | 1999 | 1998 | **2000** | 1999 | 1998 |
| Natural gas *(mmcf per day)* | | | | | | |
| US | **71.1** | 75.5 | 73.8 | **57.2** | 60.2 | 58.6 |
| UK | **5.3** | 9.8 | 8.5 | **5.3** | 9.8 | 8.5 |
| Total | **76.4** | 85.3 | 82.3 | **62.5** | 70.0 | 67.1 |
| Oil and ngls *(barrels per day)* | **4,022** | 4,611 | 3,482 | **3,396** | 3,913 | 3,012 |
| Total natural gas equivalent *(mmcfe per day)* | **100.5** | 112.9 | 103.2 | **82.9** | 93.4 | 85.2 |
| Total annual equivalent *(bcfe)* | **36.8** | 41.2 | 37.7 | **30.3** | 34.1 | 31.1 |

Our average combined natural gas and oil production rate decreased by 11% to 100.5 mmcfe per day (82.9 mmcfe per day after royalties) in 2000 from 112.9 mmcfe per day (93.4 mmcfe per day after royalties) in 1999 and 103.2 mmcfe per day (85.2 mmcfe per day after royalties) in 1998. Natural gas comprised 76% (75% after royalties) of our production volumes in both 2000 and 1999, and 80% (79% after royalties) in 1998. In 2000, natural gas production was 28.0 bcf (22.9 bcf after royalties) compared to 31.1 bcf (25.5 bcf after royalties) in 1999 and 30.0 bcf (24.5 bcf after royalties) in 1998. In 2000, oil and natural gas liquids production was 1.5 mmbbls (1.2 mmbbls after royalties) compared to 1.7 mmbbls (1.4 mmbbls after royalties) in 1999 and 1.3 mmbbls (1.1 mmbbls after royalties) in 1998.

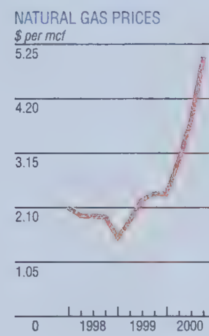
Comparing 2000 and 1999, average production rates decreased 7.4 mmcfe per day (5.5 mmcfe per day after royalties) in the US and 4.6 mmcfe per day (before and after royalties) in the UK. During 2000, US production volumes decreased compared to 1999 as a result of the concentration of production from new properties in the second half of the year. The majority of the successful wells drilled in 1999 and scheduled for development in 2000 experienced delays in both follow-up drilling and facilities design and installation, causing a greater than expected time lag in production additions. The decline in production was halted in the second quarter, and production grew through the remainder of the year. In the UK, where no further exploration and development is currently planned, production is subject to normal decline.

Comparing 1999 and 1998, production growth was primarily from properties in the US Gulf of Mexico region which produced for the first time in 1999.

Ninety-two percent of 2000 natural gas production came from our interests in 121 wells in the US Gulf of Mexico region compared to 88% (111 wells) in 1999 and 89% (108 wells) in 1998. Fifty-four percent of our 2000 and 1999 oil and ngls production came from our holdings in the US Gulf of Mexico region (1998 - 28%).

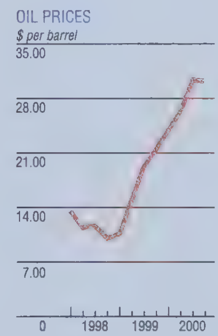
## NATURAL GAS AND OIL MARKETING

Ninety-six percent of our natural gas reserves are located in the US Gulf of Mexico region where ready deliverability through numerous large capacity pipelines and auxiliary feeder pipelines provides flexibility in marketing our production. Natural gas prices in the US and in the UK are largely determined by competitive market forces. Most of the natural gas produced by us, as well as our US Gulf of Mexico region oil and natural gas liquids production, has been marketed since 1989 by Highland Energy Company, an aggregator for several natural gas producers.




Our oil production from the Aneth and Ratherford Units in the Four Corners area of Utah has been sold under successive term contracts to a regional refiner since 1989. Due to its quantity and quality, we have obtained premiums over locally posted prices for this production.

Market prices of oil and natural gas fluctuate and can materially affect our operating results. We sell most of our natural gas under short term contractual arrangements and do not engage in speculative forward selling of volumes that cannot be physically delivered. To mitigate some of this price risk, we may enter into forward sales for a portion of our production so as to lock in a firm natural gas price for a specific volume and delivery period.



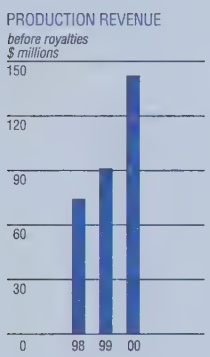

At December 31, 2000, we had entered into forward sales for the physical delivery, during the first nine months of 2001, of natural gas production totaling 7.1 bcf (approximately 15% of our forecast 2001 equivalent volume), at an average price, net of transportation, of $4.86 per mcf. At the 1999 year-end, we had entered into forward sales for the physical delivery of 2000 natural gas production of 6.1 bcf (approximately 17% of our 2000 equivalent volume) at an average price of $2.49 per mcf. Forward sales of natural gas at December 31, 1998 were immaterial. Also at December 31, 1999, we had entered into oil forward sales for the physical delivery of 90 mbbls of 2000 production at an average price of $19.00 per barrel. We had not entered into oil forward sales at either December 31, 2000 or 1998.

## *Natural Gas*

Our composite average natural gas price was $3.63 per mcf in 2000 compared to $2.02 in 1999 and $1.99 in 1998. The mild North American winter of 1998-1999 had a downward effect on 1998 US natural gas prices. During the first quarter of 1999, we received an average of $1.54 per mcf for our US natural gas. Thereafter, prices increased to an average of $2.39 per mcf in the fourth quarter of 1999. Strong demand for electricity, as well as the demand associated with replenishing storage for the forthcoming 2000-2001 winter, pulled our US natural gas price from $2.51 per mcf in the first quarter of 2000 to $3.18 per mcf and $3.84 per mcf in the second and third quarters, respectively. During the fourth quarter of 2000, the benchmark New York Mercantile Exchange natural gas futures experienced significant volatility. This is reflected in the $5.20 per mcf price realized in the fourth quarter of 2000 for our US production. For the full year 2000, our average US natural gas price was $3.76 per mcf (1999 - $2.16 per mcf; 1998 - $2.06 per mcf) and our average UK natural gas price was $1.96 per mcf (1999 - $0.96 per mcf; 1998 - $1.40 per mcf).

## *Oil and ngls*

Our average oil and ngls price per barrel was $27.72 in 2000 compared to $17.05 in 1999 and $11.74 in 1998. In 1998, the combination of economic problems in Asia, the mild North American winter and international competition for market share caused oil prices to fall. Oil prices began to recover when, in the second quarter of 1999, Organization of Petroleum Exporting Countries ("OPEC") production quotas became effective. Starting with the first quarter of 1999, we experienced seven consecutive quarters of increasing oil and ngls prices before they leveled out at a price of $30.32 per barrel in the fourth quarter of 2000.




## REVENUE

In 2000, an 80% increase in natural gas prices was complemented by a 63% increase in oil prices. Increased prices more than offset decreased production with the result that our 2000 production revenue increased 56% from 1999 to $142.4 million ($117.0 million after royalties). In 1999, growth in our combined natural gas and oil production volumes was accompanied by a recovery in commodity prices. As a result, 1999 production revenues increased 22% from 1998 to $91.5 million ($75.4 million after royalties).

| **Net Revenue** *(in thousands)* | **2000** | 1999 | 1998 |
|---|---|---|---|
| Natural gas, after royalties | **$ 82,577** | $ 50,765 | $ 48,501 |
| Oil and ngls, after royalties | **34,415** | 24,601 | 13,114 |
| Production revenue, after royalties | **116,992** | 75,366 | 61,615 |
| Interest and other revenue | **2,881** | 1,081 | 2,776 |
| Total net revenue | **$ 119,873** | $ 76,447 | $ 64,391 |

| Price/Volume Variances, After Royalties | Natural gas US | Natural gas UK | Natural gas Total | Oil and ngls | Total |
|---|---|---|---|---|---|
| *(in thousands)* | | | | | |
| 1998 production revenue, after royalties | $ 44,165 | $ 4,336 | $ 48,501 | $ 13,114 | $ 61,615 |
| Price variance | 2,064 | (1,597) | 467 | 7,626 | 8,093 |
| Volume variance | 1,102 | 695 | 1,797 | 3,861 | 5,658 |
| 1999 production revenue, after royalties | 47,331 | 3,434 | 50,765 | 24,601 | 75,366 |
| **Price variance** | **33,639** | **1,945** | **35,584** | **13,010** | **48,594** |
| **Volume variance** | **(2,197)** | **(1,575)** | **(3,772)** | **(3,196)** | **(6,968)** |
| **2000 production revenue, after royalties** | **$ 78,773** | **$ 3,804** | **$ 82,577** | **$ 34,415** | **$ 116,992** |

## Royalties

Royalties include payments made to federal and state governments, freehold land owners and other third parties. Our US Gulf of Mexico properties in US federal waters generally carry a 16-2/3% royalty rate. Some of these properties carry overriding royalties ranging from 1.1% to 10%. In 2000, the effective average overriding royalty rate was 1.9% (1999 - 2.2%; 1998 - 2.7%).

Production from the Aneth and Ratherford Units is subject to production taxes and to a 12.5% royalty. The Aneth unit carries an additional royalty burden of approximately 2%. The Northeast Wright Field, in Louisiana, is subject to a 26% royalty.

The UK properties carry no royalty obligations. As the UK properties mature, natural production declines will reduce the proportion of this production in our mix and our composite royalty per mcfe can be expected to increase.

**We pay no overriding royalties to management or staff.**

| Royalties | 2000 | 1999 | 1998 |
|---|---|---|---|
| *(in thousands except per unit amounts and percentages)* | | | |
| Natural gas | **$ 19,006** | $ 11,699 | $ 11,211 |
| Oil and ngls | **6,393** | 4,442 | 2,035 |
| Total | **$ 25,399** | $ 16,141 | $ 13,246 |
| Royalties *($ per mcfe)* | **$ 0.69** | $ 0.39 | $ 0.35 |
| Composite royalty rate | **17.8 %** | 17.6 % | 17.7 % |

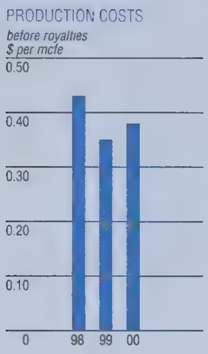
## Interest and Other Revenue

Interest and other revenue for 2000 included non-recurring revenue of $1.3 million arising from the Libyan venture which was terminated in the second quarter of 1999. Under the terms of the concession, the Libyan National Oil Company ("NOC") reimbursed us and our partners in kind for NOC's share of production test expenditures. The non-recurring revenue resulted from the increase in oil prices between the time when production test expenditures were incurred and the time when reimbursement was effected.

In 1998, interest and other revenue included a non-recurring court award of $1.6 million pursuant to a successful claim for recovery of excess transportation charges incurred from 1990 through 1997.

## EXPENSES

### *Production Costs*




Our aggregate production costs in 2000 decreased 2% compared to 1999. However, because production taxes increased 43% to $2.0 million and production volumes were lower, our per unit production costs increased. Our production costs in 1999 decreased 12% from 1998, a result of non-recurring items in 1998 and the termination of the Libyan production test in mid-1999.

Production costs for US Gulf of Mexico region properties were $0.28 per mcfe ($0.35 per mcfe after royalties) in 2000 compared to $0.25 per mcfe ($0.31 per mcfe after royalties) in 1999 and $0.32 per mcfe ($0.41 per mcfe after royalties) in 1998. Production costs for the Aneth and Ratherford Units, which are primarily oil producing properties where secondary and tertiary recovery methods are being used, were $1.28 per mcfe ($1.47 per mcfe after royalties) in 2000 compared to $1.15 per mcfe ($1.32 per mcfe after royalties) in 1999 and $0.99 per mcfe ($1.13 per mcfe after royalties) in 1998.

| **Production Costs** | **2000** | 1999 | 1998 |
|---|---|---|---|
| *(in thousands except per unit amounts)* | | | |
| Lifting costs | **$ 12,109** | $ 12,929 | $ 14,899 |
| Production taxes | **1,983** | 1,391 | 1,456 |
| Production costs | **$ 14,092** | $ 14,320 | $ 16,355 |
| Production costs *($ per mcfe)* | | | |
| Before royalty volumes | **$ 0.38** | $ 0.35 | $ 0.43 |
| After royalty volumes | **$ 0.46** | $ 0.42 | $ 0.53 |

Production from the Aneth and Ratherford Units and the Northeast Wright and Chacahoula Fields in Louisiana is subject to production and severance taxes. As a result of the price dependent methodologies used to calculate these taxes, and the anticipated additional production from the D. W. Guidry # 1 well in the Northeast Wright Field, we expect that our production taxes will increase in 2001.

## General and Administrative

Our general and administrative costs increased 31% in 2000 compared to 1999 and decreased 5% in 1999 compared to 1998. Performance-based compensation payments were higher in 2000 than in 1999 and lower in 1999 than in 1998. Also contributing to higher costs in 2000 were the hiring of three professional employees required in support of our larger role as an operator, non-recurring legal fees and increased office costs.

| **General and Administrative** *(in thousands except per unit amounts and percentages)* | **2000** | 1999 | 1998 |
|---|---|---|---|
| Gross general and administrative | **$ 12,040** | $ 8,527 | $ 9,108 |
| Capitalized | **(6,056)** | (3,947) | (4,312) |
| General and administrative expense | **$ 5,984** | $ 4,580 | $ 4,796 |
| General and administrative *($ per mcfe)* | | | |
| Before royalty volumes | **$ 0.16** | $ 0.11 | $ 0.13 |
| After royalty volumes | **$ 0.20** | $ 0.13 | $ 0.15 |
| Capitalization ratio | **50 %** | 46 % | 47 % |

## Interest

Interest expense decreased to $1.1 million in 2000 from $2.5 million in 1999 and $0.4 million in 1998. The fluctuations were largely due to varying credit facility utilization. Our weighted average debt outstanding during 2000 was $15.2 million compared to $42.1 million in 1999 and $12.3 million in 1998. The effective interest rate on our outstanding debt for 2000 was 7.32% compared to 5.93% in 1999 and 6.19% in 1998. The interest rate on our debt at December 31, 2000 was 7.63%.

## Depletion and Amortization

Depletion and amortization expense in 2000 decreased by $7.6 million, compared to 1999, of which $5.5 million related to the decrease in production and $2.1 million related to the decrease in the average depletion rate to $1.19 per mcfe ($1.44 per mcfe after royalties). Our lower finding and development costs for proved reserves in 1999, the oil price induced upward revision in our proved reserves and the ceiling test write-down of UK properties contributed to the decrease in our depletion rate in 2000.

Comparing 1999 to 1998, depletion and amortization expense increased $9.3 million, of which $4.0 million related to the increase in production and $5.3 million related to the increase in the average depletion rate to $1.25 per mcfe ($1.51 per mcfe after royalties). The downward revision in our proved reserves at December 31, 1998, the result of low oil prices at that date, contributed to the increase in our 1999 depletion rate.

We expect that our depletion rate will be approximately $1.35 per mcfe ($1.64 per mcfe after royalties) in the first quarter of 2001. The depletion rate is reviewed quarterly.

Accounting rules require that we review regularly, on a country-by-country basis, the carrying value of our oil and gas properties for possible write-down or impairment. Under these rules, capitalized costs of proved reserves are not allowed to exceed the value of estimated future net revenues from those proved reserves (the "ceiling test"). Full cost accounting rules allow, but do not require, companies to exclude costs of acquiring and evaluating unproved properties from their depletion cost centers, but if such costs are excluded, they must be separately assessed for impairment. Our policy on depletion does not exclude such costs from their respective depletion cost centers.

The Canadian full cost accounting guideline was revised during 2000 to require that a ceiling test must be conducted on a quarterly basis. We will prospectively apply this policy effective with the first quarter of 2001.

In Libya, we and our partners concluded that the multi-year exploration program, and the production test which commenced in December 1997, were not commercially viable under the terms of the concession and therefore terminated the venture. As a result, additional depletion of $11.4 million was recorded in the second quarter of 1999 to eliminate the investment. An impairment provision of $5.1 million was recorded at December 31, 1998 in respect of one of the Libyan concessions upon which no further exploration was then planned.

In respect of the UK properties, we recorded ceiling test impairments at December 31, 1999 and 1998 due to very low spot market prices for natural gas and downward reserve revisions, respectively.

### *Taxes*

We have available $230.3 million in US tax pools and $29.1 million in Canadian tax pools to reduce future taxable income. Should natural gas and oil prices remain at recent levels, we will be required to pay current income taxes in 2001 as follows:

- US Alternative Minimum Tax ("AMT"), the amounts of which are, for us, dependent upon tax loss utilization, and which can be carried forward and credited against regular tax in future years; and
- UK corporate income taxes, the amounts of which will depend primarily on UK natural gas prices, and for which we receive limited double-taxation relief both in Canada and the US.

During 2000, both the Canadian Federal and Alberta Provincial governments proposed corporate income tax rate reductions. As our deferred tax asset arises in Canada, lower corporate income tax rates reduce the future value of the tax asset. If the proposed rate reductions are all enacted the tax rate for our Canadian taxable income would fall to 30.12% in 2005, a reduction of about one-third compared to the 44.62% rate in 2000.

The Canadian Federal rate reductions were substantially enacted in 2000 and we have recorded the effect, a $1.3 million expense, in 2000. The proposed Alberta rate reductions did not satisfy the requirements for recognition in 2000. We expect that the Alberta rate reductions will be substantially enacted in 2001, at which time we will record their effect, an estimated expense of $1.3 million, thereby reducing the carrying amount of the deferred tax asset.

## NET INCOME (LOSS) APPLICABLE TO COMMON SHARES

In 2000, income before provision for dividends on preferred shares of a subsidiary increased $39.2 million to $32.3 million compared to 1999. After provision of $4.9 million for dividends on preferred shares of a subsidiary, net income applicable to common shares for 2000 was $27.3 million, an improvement of $39.2 million compared to 1999. The most significant factors responsible for the improvement were the increased natural gas and oil prices in 2000 and the non-recurring nature of the 1999 write-off of the Libyan investment.

In 1999, the loss applicable to common shares, after provision of $4.9 million for dividends on preferred shares of a subsidiary, in 1999 was $11.8 million, $2.7 million more than in 1998. Improved prices and increased production volumes realized in 1999 were more than offset by regular and additional depletion charges.

## CAPITAL EXPENDITURES

Natural resource capital expenditures were $102.7 million in 2000 compared to $55.0 million in 1999 and $92.6 million in 1998.

| **Capital Expenditures Summary** | **2000** | 1999 | 1998 |
|---|---|---|---|
| *(in thousands)* | | | |
| Property acquisition costs: | | | |
| US | **$ 7,789** | $ 5,352 | $ 7,903 |
| UK | **33** | 28 | 115 |
| | **7,822** | 5,380 | 8,018 |
| Purchase (sale) of producing properties: | | | |
| US | **–** | (155) | 883 |
| Exploration costs: | | | |
| US | **57,926** | 28,753 | 43,317 |
| UK | **9** | 9 | 72 |
| Other foreign | **–** | 1,531 | 606 |
| | **57,935** | 30,293 | 43,995 |
| Development costs: | | | |
| US | **36,943** | 19,542 | 39,606 |
| UK | **1** | (39) | 71 |
| | **36,944** | 19,503 | 39,677 |
| Total | **$ 102,701** | $ 55,021 | $ 92,573 |

### *Land and Lease Holdings*

We acquired leases in two lease sales during 2000. We participated in high bids for 14 blocks, 5 as operator, covering 72,890 acres (33,684 net acres). Our share of the bids on the blocks, all of which have been awarded, was $4.3 million. At December 31, 2000, we had an average working interest of 40% in 152 offshore blocks covering 719,798 gross acres compared to an average working interest of 40% in 139 blocks covering 661,410 gross acres a year earlier.

### *Drilling Results*

Drilling in all areas, including extensive development drilling in the Utah oil producing units in 1998, resulted in success rates of 63% in 2000, 70% in 1999 and 84% in 1998. In 2000, our exploratory drilling success rate in the US Gulf of Mexico region was 59% compared to 73% in 1999 and 43% in 1998. Including development wells, our success rate in the region was 63% in 2000 compared to 78% in 1999 and 58% in 1998.

| Drilling Results | 2000 | | 1999 | | 1998 | |
|---|---|---|---|---|---|---|
| | **Gross** | **Net** | Gross | Net | Gross | Net |
| *(wells)* | | | | | | |
| US - Gulf of Mexico region | | | | | | |
| Successful | **22** | **8.38** | 14 | 5.37 | 11 | 2.79 |
| Dry | **13** | **4.80** | 4 | 1.70 | 8 | 3.45 |
| | **35** | **13.18** | 18 | 7.07 | 19 | 6.24 |
| US - Other | | | | | | |
| Successful | **–** | **–** | – | – | 30 | 6.01 |
| Dry | **–** | **–** | – | – | – | – |
| | **–** | **–** | – | – | 30 | 6.01 |
| Total US | | | | | | |
| Successful | **22** | **8.38** | 14 | 5.37 | 41 | 8.80 |
| Dry | **13** | **4.80** | 4 | 1.70 | 8 | 3.45 |
| | **35** | **13.18** | 18 | 7.07 | 49 | 12.25 |
| Foreign | | | | | | |
| Dry | **–** | **–** | 2 | 0.25 | – | – |
| Total wells drilled | | | | | | |
| Successful | **22** | **8.38** | 14 | 5.37 | 41 | 8.80 |
| Dry | **13** | **4.80** | 6 | 1.95 | 8 | 3.45 |
| | **35** | **13.18** | 20 | 7.32 | 49 | 12.25 |

In addition to the wells described above, at December 31, 2000 we had an interest in one (0.67 net) well which was drilling. At December 31, 1999 we had interests in three (0.62 net) wells which were drilling and one (0.50 net) well which was being evaluated. No wells were being drilled or evaluated at December 31, 1998.

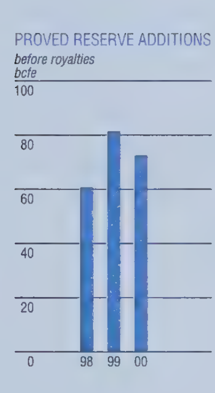
Three wells were drilled in 2000 on our leases in the US Gulf of Mexico region at no cost to us; two are natural gas wells and one was being evaluated at year-end. In 1999, five wells were drilled on our acreage in the region at no cost to us; one resulted in a natural gas well and four were unsuccessful. In 1998, one successful natural gas well was drilled on our acreage at no cost to us.

### *Capital Field Development Activity*

During 2000, design, construction and/or installation of production facilities and pipelines, which are the components of our capital field development, totaled $25.9 million and were principally at Eugene Island 189, High Island A-510/A-531, High Island A-530, Matagorda Island 704, South Timbalier 196, Vermilion 267, West Cameron 300 and West Cameron 613/614 where production facilities and, except at Eugene Island 189 and High Island A-510/A-531, pipelines, were installed. Onshore, facilities were completed for the Langlinais #1 well in the Northeast Wright Field and at Chacahoula.

## FINDING AND DEVELOPMENT COSTS

### *Cost of Reserve Additions*

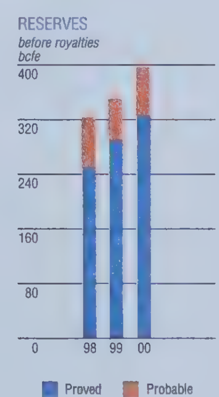



Three year finding and development costs of proved reserves were $1.17 per mcfe ($1.50 per mcfe after royalties). The upward pressure on exploration service and supply costs is the primary reason for the increase from the 1999 three year finding and development cost of $1.15 per mcfe ($1.45 per mcfe after royalties). The 1998 three year finding and development costs were $1.51 per mcfe ($1.89 per mcfe after royalties).

In calculating finding costs, a number of anomalies between periods are created by the timing of expenditures and the phase of the exploration and production cycle. This relates particularly to lease acquisitions and to major facility construction, as well as to recognition and revision of reserves. Multi-year cumulative average calculations are a more meaningful reflection of a company's ability to find and produce reserves. Finding costs are calculated by dividing capital expenditures for a period by proved reserve additions (before production) for the same period. Both a three-year calculation and one year components are included in the following table.

| **Finding Cost Analysis** | **2000** | 1999 | 1998 | Cumulative 1998-2000 |
|---|---|---|---|---|
| *(in thousands except unit and per unit amounts)* | | | | |
| Capital expenditures | **$ 102,701** | $ 55,021 | $ 92,573 | $ 250,295 |
| Proved, before royalties | | | | |
| Reserve additions *(mmcfe)* | **72,354** | 80,898 | 59,999 | 213,251 |
| Finding costs *($ per mcfe)* | **$ 1.42** | $ 0.68 | $ 1.54 | $ 1.17 |
| Proved, after royalties | | | | |
| Reserve additions *(mmcfe)* | **56,164** | 65,796 | 45,381 | 167,341 |
| Finding costs *($ per mcfe)* | **$ 1.83** | $ 0.84 | $ 2.04 | $ 1.50 |

### *Reserve Replacement*




For the seventh consecutive year, we added more proved reserves than we produced with total proved reserves increasing to 326 bcfe (266 bcfe after royalties). The increase of 72.4 bcfe (56.2 bcfe after royalties), before production, results in a reserve replacement rate of 197% (185% after royalties). Proved and probable reserves increased to 398 bcfe (324 bcfe after royalties).

## RESERVES

Reports prepared by Netherland, Sewell & Associates, Inc., independent petroleum engineers, as to our US reserves and internally as to our UK reserves, contain estimates of our total proved reserves, before and after royalty deductions, as described below. UK reserves comprise 1.9% (2.3% after royalties) of our total proved reserves on a bcfe basis.

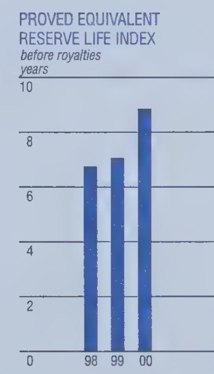
| Reserve Reconciliation – Natural Gas | Before royalties | | | After royalties | | |
|---|---|---|---|---|---|---|
| | Proved | Probable | Proved + probable | Proved | Probable | Proved + probable |
| *(mmcf)* | | | | | | |
| December 31, 1998 | 159,064 | 52,647 | 211,711 | 129,073 | 42,753 | 171,826 |
| Purchase of producing properties | – | – | – | – | – | – |
| Revision of previous estimates | (5,786) | (21,429) | (27,215) | (4,858) | (17,607) | (22,465) |
| Extensions, discoveries and other additions | 64,127 | 17,558 | 81,685 | 51,251 | 13,579 | 64,830 |
| Sale of proved properties | – | – | – | – | – | – |
| Net additions | 58,341 | (3,871) | 54,470 | 46,393 | (4,028) | 42,365 |
| Production | (31,119) | – | (31,119) | (25,533) | – | (25,533) |
| December 31, 1999 | 186,286 | 48,776 | 235,062 | 149,933 | 38,725 | 188,658 |
| **Purchase of producing properties** | **2,741** | **711** | **3,452** | **1,839** | **477** | **2,316** |
| **Revision of previous estimates** | **31,485** | **(13,653)** | **17,832** | **23,942** | **(10,470)** | **13,472** |
| **Extensions, discoveries and other additions** | **41,280** | **22,942** | **64,222** | **34,019** | **18,815** | **52,834** |
| **Sale of proved properties** | **–** | **–** | **–** | **–** | **–** | **–** |
| **Net additions** | **75,506** | **10,000** | **85,506** | **59,800** | **8,822** | **68,622** |
| **Production** | **(27,956)** | **–** | **(27,956)** | **(22,871)** | **–** | **(22,871)** |
| **December 31, 2000** | **233,836** | **58,776** | **292,612** | **186,862** | **47,547** | **234,409** |

| Reserve Reconciliation – Oil and ngls | Before royalties | | | After royalties | | |
|---|---|---|---|---|---|---|
| | Proved | Probable | Proved + probable | Proved | Probable | Proved + probable |
| *(mbbls)* | | | | | | |
| December 31, 1998 | 15,227 | 3,438 | 18,665 | 13,134 | 2,868 | 16,002 |
| Purchase of producing properties | – | – | – | – | – | – |
| Revision of previous estimates | 1,607 | (2,028) | (421) | 1,480 | (1,682) | (202) |
| Extensions, discoveries and other additions | 2,152 | 639 | 2,791 | 1,753 | 518 | 2,271 |
| Sale of proved properties | – | – | – | – | – | – |
| Net additions | 3,759 | (1,389) | 2,370 | 3,233 | (1,164) | 2,069 |
| Production | (1,656) | – | (1,656) | (1,401) | – | (1,401) |
| December 31, 1999 | 17,330 | 2,049 | 19,379 | 14,966 | 1,704 | 16,670 |
| **Purchase of producing properties** | **99** | **31** | **130** | **66** | **21** | **87** |
| **Revision of previous estimates** | **(863)** | **(7)** | **(870)** | **(868)** | **15** | **(853)** |
| **Extensions, discoveries and other additions** | **239** | **89** | **328** | **196** | **73** | **269** |
| **Sale of proved properties** | **–** | **–** | **–** | **–** | **–** | **–** |
| **Net additions** | **(525)** | **113** | **(412)** | **(606)** | **109** | **(497)** |
| **Production** | **(1,472)** | **–** | **(1,472)** | **(1,243)** | **–** | **(1,243)** |
| **December 31, 2000** | **15,333** | **2,162** | **17,495** | **13,117** | **1,813** | **14,930** |

| Reserve Reconciliation – Equivalent | Before royalties | | | After royalties | | |
|---|---|---|---|---|---|---|
| | Proved | Probable | Proved + probable | Proved | Probable | Proved + probable |
| *(mmcfe)* | | | | | | |
| December 31, 1998 | 250,426 | 73,275 | 323,701 | 207,877 | 59,961 | 267,838 |
| Purchase of producing properties | – | – | – | – | – | – |
| Revision of previous estimates | 3,857 | (33,598) | (29,741) | 4,022 | (27,699) | (23,677) |
| Extensions, discoveries and other additions | 77,041 | 21,390 | 98,431 | 61,774 | 16,682 | 78,456 |
| Sale of proved properties | – | – | – | – | – | – |
| Net additions | 80,898 | (12,208) | 68,690 | 65,796 | (11,017) | 54,779 |
| Production | (41,055) | – | (41,055) | (33,939) | – | (33,939) |
| December 31, 1999 | 290,269 | 61,067 | 351,336 | 239,734 | 48,944 | 288,678 |
| **Purchase of producing properties** | **3,335** | **897** | **4,232** | **2,235** | **603** | **2,838** |
| **Revision of previous estimates** | **26,307** | **(13,695)** | **12,612** | **18,734** | **(10,380)** | **8,354** |
| **Extensions, discoveries and other additions** | **42,712** | **23,478** | **66,190** | **35,195** | **19,253** | **54,448** |
| **Sale of proved properties** | **–** | **–** | **–** | **–** | **–** | **–** |
| **Net additions** | **72,354** | **10,680** | **83,034** | **56,164** | **9,476** | **65,640** |
| **Production** | **(36,788)** | **–** | **(36,788)** | **(30,329)** | **–** | **(30,329)** |
| **December 31, 2000** | **325,835** | **71,747** | **397,582** | **265,569** | **58,420** | **323,989** |

| Proved Reserve Life Index | Before royalties | | | After royalties | | |
|---|---|---|---|---|---|---|
| | **2000** | 1999 | 1998 | **2000** | 1999 | 1998 |
| *(years)* | | | | | | |
| Natural gas | **8.4** | 6.0 | 5.3 | **8.2** | 5.9 | 5.3 |
| Oil and ngls | **10.4** | 10.5 | 13.0 | **10.6** | 10.7 | 13.2 |
| Equivalent | **8.9** | 7.1 | 6.8 | **8.8** | 7.1 | 6.8 |

Reserve life indexes are calculated by dividing year-end reserve volumes by the year's production volumes. At the end of 2000, if 50% of probable reserves are included in the calculation, the equivalent reserve life index is 9.8 years (9.7 years after royalties) and if 100% of probable reserves are included in the calculation the equivalent reserve life index is 10.8 years (10.7 years after royalties). For 1999 and 1998, if 50% of probable reserves are included in the calculation, the equivalent reserve life indexes would be 7.8 years (before and after royalties) and 7.7 years (7.8 years after royalties), respectively. If 100% of probable reserves are included in the calculation, for 1999 and 1998 the equivalent reserve life indexes would be 8.6 years (8.5 years after royalties) and 8.7 years (8.8 years after royalties), respectively.



| Reserve Summary - Natural Gas | Before royalties 2000 | 1999 | 1998 | After royalties 2000 | 1999 | 1998 |
|---|---|---|---|---|---|---|
| *(mmcf)* | | | | | | |
| Proved reserves: | | | | | | |
| Developed producing - US | **98,625** | 63,822 | 70,082 | **77,699** | 50,531 | 55,418 |
| - UK | **5,985** | 6,376 | 10,108 | **5,985** | 6,376 | 10,108 |
| Developed non-producing - US | **37,833** | 58,986 | 41,974 | **30,481** | 46,024 | 33,906 |
| Undeveloped - US | **91,393** | 57,102 | 36,900 | **72,697** | 47,002 | 29,641 |
| Total proved reserves | **233,836** | 186,286 | 159,064 | **186,862** | 149,933 | 129,073 |
| Probable reserves - US | **57,330** | 46,694 | 49,630 | **46,101** | 36,643 | 39,736 |
| - UK | **1,446** | 2,082 | 3,017 | **1,446** | 2,082 | 3,017 |
| Total probable reserves | **58,776** | 48,776 | 52,647 | **47,547** | 38,725 | 42,753 |
| Total proved and probable reserves | **292,612** | 235,062 | 211,711 | **234,409** | 188,658 | 171,826 |

| Reserve Summary - Oil and ngls | Before royalties 2000 | 1999 | 1998 | After royalties 2000 | 1999 | 1998 |
|---|---|---|---|---|---|---|
| *(mbbls)* | | | | | | |
| Proved reserves: | | | | | | |
| Developed producing - US | **6,893** | 7,447 | 5,430 | **6,002** | 6,580 | 4,739 |
| - UK | **19** | 20 | 27 | **19** | 20 | 27 |
| Developed non-producing - US | **1,315** | 1,633 | 3,329 | **1,092** | 1,347 | 2,768 |
| Undeveloped - US | **7,106** | 8,230 | 6,441 | **6,004** | 7,019 | 5,600 |
| Total proved reserves | **15,333** | 17,330 | 15,227 | **13,117** | 14,966 | 13,134 |
| Probable reserves - US | **2,157** | 2,043 | 3,430 | **1,808** | 1,698 | 2,860 |
| - UK | **5** | 6 | 8 | **5** | 6 | 8 |
| Total probable reserves | **2,162** | 2,049 | 3,438 | **1,813** | 1,704 | 2,868 |
| Total proved and probable reserves | **17,495** | 19,379 | 18,665 | **14,930** | 16,670 | 16,002 |

### *Net Future Capital Expenditures*

The reserve reports incorporate estimated future capital expenditures, of which 89% will be spent over the next five years, that are required to bring proved undeveloped reserves to production, to maintain proved producing reserves, and to provide for future abandonment.

| Net Future Capital Expenditures | 2000 | 1999 | 1998 |
|---|---|---|---|
| *(in thousands)* | | | |
| Proved developed | **$ 24,672** | $ 28,120 | $ 29,131 |
| Proved undeveloped | **97,056** | 56,753 | 32,532 |
| Total | **$ 121,728** | $ 84,873 | $ 61,663 |

### *Reserve Value Reconciliation*

As required by the Financial Accounting Standards Board Statement 69, our reserves were estimated using year-end prices which, at December 31, 2000, were $24.60 per barrel for oil and $9.68 per mcf for US natural gas. The resulting estimated present values of proved reserves are not considered to be estimates of fair market value. **We therefore caution against simplistic use of this information.**

| **Estimated Present Value of Proved Reserves** | **2000** | 1999 | 1998 |
|---|---|---|---|
| *(in thousands)* | | | |
| Proved developed | **$ 798,646** | $ 193,935 | $ 135,867 |
| Proved undeveloped | **428,313** | 72,539 | 16,641 |
| Total PV-10 value before income taxes | **$ 1,226,959** | $ 266,474 | $ 152,508 |
| Standardized measure of discounted estimated future net cash flows after income taxes | **$ 849,465** | $ 224,533 | $ 152,508 |

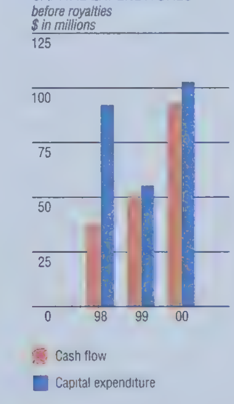
| **Prices Used in Calculating Proved Reserves** | **2000** | 1999 | 1998 |
|---|---|---|---|
| Natural gas *(per mcf)* | | | |
| US | **$ 9.68** | $ 2.51 | $ 2.15 |
| UK | **$ 3.65** | $ 0.99 | $ 1.74 |
| Oil and ngls *(per barrel)* | **$ 24.60** | $ 20.40 | $ 9.72 |

## CAPITAL RESOURCES AND LIQUIDITY

Our primary sources of cash are funds generated from operations and financing activities. Our primary cash outflows are for exploration and development activities.

Cash flow from operations, a frequently used measure of performance for exploration and production companies, is derived by adjusting net income (loss) attributable to common shares to eliminate the effects of depletion and amortization, additional depletion, write-down of marketable securities and deferred income taxes. We generated cash flow from operations of $93.6 million in 2000 compared to $50.1 million in 1999 and $37.8 million in 1998. The variances are primarily a function of fluctuating revenues caused by the volatility of commodity prices.

CASH FLOW VS.
CAPITAL EXPENDITURES
*before royalties*
*$ in millions*



| Cash Flow From Operations Per Unit Analysis | Before royalties 2000 | Before royalties 1999 | Before royalties 1998 | After royalties 2000 | After royalties 1999 | After royalties 1998 |
|---|---|---|---|---|---|---|
| *($ per mcfe)* | | | | | | |
| Gross production revenue | **$ 3.87** | $ 2.22 | $ 1.99 | | | |
| Royalties | **(0.69)** | (0.39) | (0.35) | | | |
| Production revenue, after royalties | **3.18** | 1.83 | 1.64 | **$ 3.86** | $ 2.21 | $ 1.98 |
| Production costs | **(0.38)** | (0.35) | (0.43) | **(0.46)** | (0.42) | (0.53) |
| Gross margin | **2.80** | 1.48 | 1.21 | **3.40** | 1.79 | 1.45 |
| General and administrative expenses | **(0.16)** | (0.11) | (0.13) | **(0.20)** | (0.13) | (0.15) |
| Gross profit | **2.64** | 1.37 | 1.08 | **3.20** | 1.66 | 1.30 |
| Interest and other | **0.04** | (0.03) | 0.05 | **0.05** | (0.04) | 0.08 |
| Preferred share dividends | **(0.13)** | (0.12) | (0.13) | **(0.16)** | (0.15) | (0.16) |
| Cash flow from operations | **$ 2.55** | $ 1.22 | $ 1.00 | **$ 3.09** | $ 1.47 | $ 1.22 |
| Annual production volume *(bcfe)* | **36.8** | 41.2 | 37.7 | **30.3** | 34.1 | 31.1 |

In 1997, a third party sold its interests in producing properties that we currently operate and since that time neither the vendor nor the purchaser has reimbursed us on a timely basis for expenditures made by us, as operator, for their account. Accordingly, we commenced an action in the Louisiana courts against both the vendor and the purchaser to recover the amounts currently owing to us, approximately $4.6 million, plus interest and costs. Although the purchaser filed for Chapter 11 bankruptcy in the first half of 2000, we currently expect to recover all current and future amounts outstanding and have therefore made no allowance for doubtful collectability.

Our financing activities in 2000 provided $6.7 million of cash, the net result of:

- the drawdown of $10 million of our revolving credit facility;
- the exercise of employee share options for $1.6 million; and
- the purchase for cancellation of 228,600 common shares for $4.9 million under a share repurchase program which expires on August 14, 2001.

Our financing activities in 1999 provided $16.2 million of cash, the net result of:

- the sale of 2,875,000 common shares for $46.3 million, net of issue costs;
- the net repayment of $30 million of our revolving credit facility; and
- the purchase for cancellation of 7,500 common shares for $0.1 million under a share repurchase program which expired on November 1, 1999.

Financing activities during 1998 provided $34.5 million of cash, the net result of:

- the drawdown of $40 million of our revolving credit facility;
- the exercise of employee share options for $0.4 million; and
- the purchase for cancellation of 294,700 common shares for $5.9 million under a share repurchase program.

Cash used in natural resource investing activities increased to $102.7 million for 2000 compared to $55.0 million and $92.6 million for 1999 and 1998, respectively. The components of our natural resource investing activities are as follows:

| **Natural Resource Investing Activities** | **2000** | 1999 | 1998 |
|---|---|---|---|
| *(in thousands)* | | | |
| Leasehold and seismic | **$ 11,195** | $ 7,854 | $ 10,757 |
| Purchase (sale) of producing properties | **–** | (155) | 883 |
| Exploratory drilling | **54,562** | 27,819 | 41,256 |
| Development drilling | **10,995** | 9,775 | 16,517 |
| Capital field development | **25,949** | 9,728 | 23,160 |
| Total | **$ 102,701** | $ 55,021 | $ 92,573 |

Early in the fourth quarter of 2000, we purchased $5 million of marketable securities. A $1.1 million write-down of the marketable securities, to a carrying amount approximating their fair value, was recorded at December 31, 2000. Concurrent with the purchase of these shares, we entered into an agreement giving us an option to acquire Qatari petroleum and natural gas interests. Early in 2001, the option expired, unexercised.

Our December 31, 2000 cash balance was $8.7 million (1999 - $19.4 million; 1998 - $10.6 million). We had outstanding borrowings of $20 million on our revolving bank credit facility at December 31, 2000 (1999 - $10 million; 1998 - $40 million). During the third quarter of 2000, our revolving bank credit facility was reduced to $70 million upon the withdrawal from the syndicate of one lender for reasons unrelated to us. The original amount of the facility was $100 million. With no immediate need for the $30 million difference, we have decided to not pursue an immediate replacement for the withdrawn syndicate member. The weighted average interest rate on our borrowings for 2000 was 7.32% (1999 - 5.93%; 1998 - 6.19%).

## RISK ASSESSMENT

There are a number of risks facing the oil and gas industry. Some are common to all businesses while others are industry specific. The following review includes our approach to managing various risks.

### *Operational Risks*

Exploration for and production of oil and natural gas can be hazardous, involving natural disasters and other unforeseen occurrences such as blowouts, cratering, fires and loss of well control, which can damage or destroy wells or production facilities, can result in the injury or death of people, and can damage property and the environment.

We seek to mitigate the foregoing risks by maintaining prudent levels of insurance against many potential losses and liabilities arising from our operations. However, in accordance with customary industry practice, we may not be fully insured against these risks, nor may all such risks be insurable.

Unless we successfully replace our reserves, our production will decline, resulting in lower revenues and cash flow. Replacing our reserves is particularly important because most of our reserves are in the US Gulf of Mexico where wells normally have steeper rates of decline than onshore wells. Exploring for oil and natural gas and developing oil and natural gas properties require significant capital expenditures and involve a high degree of financial risk. The budgeted costs of drilling, completing and operating wells are often exceeded and can increase significantly when rig supply tightens and drilling costs rise. Drilling may be unsuccessful for many reasons, including the inherent imprecision of geological interpretation, weather, cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of an oil or gas well does not ensure a profit on investment.

Exploratory wells bear a much greater risk of loss than development wells. A variety of factors, both geological and market-related, can cause a well to become uneconomic or only marginally economic. In addition to their costs, unsuccessful wells can harm our efforts to replace reserves.

We seek to limit our financial and operating risks in some projects by participating in drilling with industry partners and operators. We believe this strategy limits our risk exposure, particularly in high potential prospects. We also seek to operate projects in which we participate in order to better control costs and timing. Additionally, we have increasingly relied on advanced technologies, including 3D seismic analysis, to define geologic risks, thereby enhancing the results of our drilling efforts.

## *Environmental and Safety Risks*

US exploration, production and marketing operations are regulated extensively at the federal, state and local levels. These regulations affect costs, manner and feasibility of our operations. Changes in, or additions to, regulations regarding the protection of the environment could increase our compliance costs and may negatively affect our business. US offshore oil and gas operations are subject to regulations of the US Department of the Interior which currently imposes absolute liability upon the lessee under a federal lease for the cost of pollution clean-up resulting from the lessee's operations, and could subject the lessee to possible liability for pollution damage.

In the UK, deposits of substances or articles at sea from offshore oil and gas operations are subject to the licensing control of the Ministry of Agriculture, Fisheries and Food.

At present, we believe that our properties are being operated in compliance with applicable environmental laws and regulations. We do not anticipate that we will be required in the foreseeable future to expend amounts that are unusual, in relation to customary industry experience, by reason of environmental laws and regulations, but we are unable to quantify the ultimate cost of compliance.

## *Marketing Risks*

There is uncertainty as to the prices at which gas and oil we produce may be sold, and it is possible that under some market conditions the production of gas and oil from some of our properties may not be commercially viable. The availability of a ready market for gas and oil as produced and the price obtained for such gas and oil depend upon numerous factors beyond our control, including market considerations, the proximity and capacity of gas and oil pipelines and processing equipment and governmental regulation. In recent years, markets for natural gas in the US have been characterized by periods of unbalanced supply and demand. There have been significant fluctuations in prices for both gas and oil in recent years and there can be no assurance that prices for gas or oil will not decrease in the future.

Prices for oil and natural gas are volatile and declined significantly during the second half of 1998 and early 1999. The recovery in prices, which started in 1999, continued through 2000, as did price volatility. Natural gas prices affect us more than oil prices as natural gas was 76% (75% after royalties) of our 2000 and 1999 energy equivalent production and 80% (79% after royalties) of our 1998 energy equivalent production. Primarily because of lower prices, we recorded ceiling test write-downs of the UK assets in 1999 and 1998.

Most of the factors which affect natural gas and oil prices are beyond our control, such as demand, worldwide economic conditions, weather conditions, supply levels, import prices, political conditions in major oil producing regions, especially the Middle East, and actions taken by the OPEC.

We could be required to write down the carrying value of our natural gas and oil properties in the future if natural gas and oil prices are depressed for even a short period of time, are unusually volatile or if we have substantial downward revisions to our proved reserve quantities. Any such ceiling test write-down would result in a charge to earnings and a reduction of shareholders' equity, but would not affect our cash flow from operating activities. Once incurred, these write-downs cannot be reversed at a later date.

## CORPORATE GOVERNANCE

We are proponents of and apply sound corporate governance practices, as described on page 61.

## OUTLOOK AND PROSPECTS FOR FUTURE GROWTH

### *Our Strategy*

Our strategy is to increase our reserves, production, revenue and cash flow through exploration and development drilling and through the acquisition of leasehold acreage and producing properties. The elements of our strategy include the following:

- *Focus on the US Gulf of Mexico region.* We focus our operations on the US Gulf of Mexico region where we have acquired a significant exploration acreage position and assembled a substantial 3D seismic database. We believe this region combines significant geological potential, reservoir size, quality and deliverability with favorable commodity pricing and attractive finding, development and operating costs.

- *Grow through exploration.* We are pursuing an active technology-driven exploration program that is designed to balance projects with lower risk and moderate potential with drilling prospects which have higher risk and substantial potential. We generate exploration prospects through geological and geophysical analysis of 3D seismic and other data and also review prospects generated by others. Our Board of Directors has approved a 2001 budget of $105 million for exploration and development capital expenditures and we expect to use approximately $65 million of this amount for exploration activities. We are currently drilling or plan to drill approximately 36 gross exploratory and development wells in the US Gulf of Mexico region in 2001. Approximately three-quarters of these will be exploratory wells and the remainder are development wells to follow up previous discoveries.

- *Manage drilling risks through joint ventures and the use of advanced technologies.* This element of our strategy is described under Operational Risks on page 29.

- *Evaluate and pursue strategic acquisitions.* We continually review opportunities to acquire leasehold acreage and producing properties. We seek to acquire properties that we believe have significant exploration potential and to increase our working interests in producing lease blocks when available to us on economically favorable terms.

## Our Strengths

We believe that our future performance and historical success are directly related to the following combination of strengths:

- *Financial capability and flexibility.* At December 31, 2000, $50 million was available under our unsecured revolving credit facility. We seek to maintain low levels of debt in order to be able to respond quickly to drilling or acquisition opportunities.
- *Substantial inventory of drilling projects in the US Gulf of Mexico region.* In the US Gulf of Mexico region, we continue to generate, and maintain, a two year inventory of drilling prospects. All of these locations have been evaluated and defined using 3D seismic data. Our large inventory permits us to be flexible in project selection and in the timing of drilling. By identifying new exploration targets and acquiring additional acreage, we continually add to our drilling inventory.
- *Proven exploratory expertise.* Our ability to define and participate in successful prospects in the US Gulf of Mexico is demonstrated by our three year exploratory drilling success rate in the US Gulf of Mexico region of 58%.
- *Experienced technical team.* Our technical team is comprised of highly respected industry professionals with an average of more than 20 years of industry experience. Our exploration success is a direct result of this team's geologic, geophysical, engineering and technical analysis.

## Our Look Forward

The fundamentals for US natural gas marketing remain positive. The US Energy Information Administration ("EIA") reports that US natural gas demand increased by 3.7% during 2000. For 2001, the EIA forecasts that consumption will be 23.35 trillion cubic feet, an increase of 3% from 2000 levels, even though it expects wellhead natural gas prices to average $5.22 per mcf. The strong demand for electricity continues to increase the requirement for natural gas-fired generation. This, combined with the competing demand for natural gas to refill storage, should support continued price strength. At year-end 2000, the American Gas Association reported that storage volumes were 23% lower than the comparative average for 1996-1998 and 29% lower than at year-end 1999.

On the natural gas supply side, low commodity prices in 1998 and 1999 dramatically reduced drilling. This downturn limited domestic production to 18.6 trillion cubic feet in 2000, an increase of less than 1% from 1999. The EIA is forecasting that increased drilling activity will support a 5.3% increase in domestic production in 2001. The active rig count in the US declined by 24% in 1999 to average 625 active rigs compared to 827 in 1998, according to Baker Hughes. In comparison, the active rig count increased 47% to average 918 in 2000 and had increased to 1,128 by the third week of January 2001. This increased level of activity reflects the recovery in commodity prices.

The experience of 2000 confirmed the earlier conclusion of many industry observers that the natural gas supply and demand equation was tightening up in the US. The balancing of natural gas supply and demand will continue to confer benefits on properly poised companies in our industry. We believe that adherence to our strategy will bring continued growth, and maintain a strong balance sheet which will, in turn, allow us to be opportunistic and to grow, during periods of both low and high prices. Our current 2001 exploration and development budget, which we plan to fund from operating cash flow, is expected to increase 2001 production volumes to 125 mmcfe per day, 24% above 2000 levels. In 2001, we will benefit from the commencement of production from a number of new offshore facilities.

Our capital expenditures can vary significantly with exploration results, availability of equipment and services and opportunities. We will continue to monitor capital spending and adjust investment levels in relation to cash flow projections. If reductions were required to be made to our budgeted 2001 capital expenditures, economic merit and a longer term view would be used to make such decisions. Specifically, fewer wildcat wells could be drilled (either delayed or deleted), bidding at lease sales could be curtailed and seismic data acquisition could be reduced. If our budgeted 2001 capital expenditures were to be increased, for reasons other than cost overruns or expenditures contingent on successful drilling, great care would be taken to ensure that our associated human resources would be adequate. The nature of such increased capital expenditures would be dependent upon the opportunities that arise.

Our long-term growth is dependent upon our ability to effectively reinvest cash flow. While increased production volumes will improve cash flow, oil and natural gas prices will have the most significant effect on cash flow levels. Our view of natural gas prices in the US Gulf of Mexico region remains optimistic. We believe that the control on oil prices that can be exerted by OPEC has been amply demonstrated over the past few years. Should OPEC continue to adhere to its production quotas, we expect that WTI prices well in excess of $20 per barrel will continue to prevail.

## MANAGEMENT'S REPORT

The accompanying consolidated financial statements and all information in this annual report are the responsibility of management. The financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. The financial information contained elsewhere in this annual report is consistent with the consolidated financial statements in all material respects.

The Company maintains accounting systems and internal controls to provide reasonable assurance that its financial information is reliable and accurate, and that its assets are adequately safeguarded. Where necessary, management has made informed judgments and estimates in the preparation of the financial statements.

Independent auditors, appointed by the shareholders, have examined the consolidated financial statements. The Audit Committee of the Board of Directors meets periodically with management and the independent auditors to review audit, internal control, accounting policy and financial reporting matters.

The annual consolidated financial statements are approved by the Board of Directors on the recommendation of the Audit Committee.

S.A. Milner
President and Chief Executive Officer

R.J. Stefure
Vice President and Controller

February 1, 2001

# AUDITORS' REPORT

We have audited the consolidated balance sheets of Chieftain International, Inc. as at December 31, 2000 and 1999 and the consolidated statements of income (loss) and deficit and cash flows for each of the years in the three-year period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian and United States generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2000 and 1999 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2000 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Edmonton, Alberta

February 1, 2001

# CONSOLIDATED BALANCE SHEET

## *Chieftain International, Inc. and Subsidiary Companies*

| (Full Cost Method of Accounting) as at December 31, | 2000 | 1999 |
|---|---|---|
| *(US$ in thousands)* | | |
| **Assets** | | |
| Current assets: | | |
| Cash and short-term deposits | $ 8,718 | $ 19,368 |
| Accounts receivable | 32,926 | 18,855 |
| Other | 754 | 750 |
| Marketable securities | 3,913 | – |
| | 46,311 | 38,973 |
| Capital assets, at cost: | | |
| Natural resource properties including exploration and development thereon (Note 2) | 710,102 | 607,401 |
| Other capital assets | 2,241 | 2,157 |
| | 712,343 | 609,558 |
| Less: Accumulated depletion and amortization | 374,940 | 332,409 |
| | 337,403 | 277,149 |
| Deferred income taxes | 11,746 | 14,636 |
| | $ 395,460 | $ 330,758 |
| **Liabilities and Shareholders' Equity** | | |
| Current liabilities: | | |
| Accounts payable and accrued | $ 36,349 | $ 25,369 |
| Long-term debt (Note 3) | 20,000 | 10,000 |
| Abandonment cost accrual | 9,728 | 8,595 |
| Deferred income taxes | 34,237 | 15,693 |
| Shareholders' equity: | | |
| Preferred shares of a subsidiary (Note 4) | 63,403 | 63,403 |
| Share capital (Note 5) – | | |
| Authorized – an unlimited number of – | | |
| First preferred shares | | |
| Second preferred shares | | |
| Common shares | | |
| Issued – | | |
| 16,100,827 common shares (1999 – 16,224,059) | 235,295 | 237,076 |
| Contributed surplus | – | 26 |
| Deficit | (3,552) | (29,404) |
| | 295,146 | 271,101 |
| | $ 395,460 | $ 330,758 |

Approved by the Board:

S.A. Milner, Director

L.G. Munin, Director

## CONSOLIDATED STATEMENT OF INCOME (LOSS) AND DEFICIT

### *Chieftain International, Inc. and Subsidiary Companies*

| Year ended December 31, | 2000 | 1999 | 1998 |
|---|---|---|---|
| *(US$ in thousands except per share amounts)* | | | |
| Production revenue | **$ 142,391** | $ 91,507 | $ 74,861 |
| Less: royalties | **25,399** | 16,141 | 13,246 |
| Production revenue, after royalties | **116,992** | 75,366 | 61,615 |
| Interest and other revenue (Note 6) | **2,881** | 1,081 | 2,776 |
| | **119,873** | 76,447 | 64,391 |
| Production costs | **14,092** | 14,320 | 16,355 |
| General and administrative expenses | **5,984** | 4,580 | 4,796 |
| Interest | **1,131** | 2,496 | 437 |
| Depletion and amortization | **43,770** | 51,385 | 42,081 |
| Additional depletion | **–** | 16,186 | 6,244 |
| Write-down of marketable securities | **1,079** | – | – |
| | **66,056** | 88,967 | 69,913 |
| Income (loss) before income taxes and dividends on preferred shares of a subsidiary | **53,817** | (12,520) | (5,522) |
| Income taxes (Note 7): | | | |
| Current | **93** | 11 | 14 |
| Deferred | **21,434** | (5,634) | (1,423) |
| | **21,527** | (5,623) | (1,409) |
| Income (loss) before dividends on preferred shares of a subsidiary | **32,290** | (6,897) | (4,113) |
| Dividends paid on preferred shares of a subsidiary | **4,942** | 4,942 | 4,942 |
| Net income (loss) applicable to common shares | **27,348** | (11,839) | (9,055) |
| Deficit, beginning of year | **(29,404)** | (17,565) | (7,089) |
| Cost of purchase of common shares in excess of stated capital (Note 5) | **(1,496)** | – | (1,421) |
| Deficit, end of year | **$ (3,552)** | $ (29,404) | $ (17,565) |
| Net income (loss) per common share (Note 8): | | | |
| Basic | **$ 1.69** | $ (0.86) | $ (0.67) |
| Diluted (Note 1 (i)) | **$ 1.64** | $ (0.86) | $ (0.67) |
| Weighted average number of common shares outstanding (in thousands): | | | |
| Basic | **16,183** | 13,701 | 13,480 |
| Diluted | **19,745** | 13,701 | 13,480 |

# CONSOLIDATED STATEMENT OF CASH FLOWS

***Chieftain International, Inc. and Subsidiary Companies***

| Year ended December 31, | **2000** | 1999 | 1998 |
|---|---|---|---|
| *(US$ in thousands except per share amounts)* | | | |
| Operating activities: | | | |
| Net income (loss) applicable to common shares | **$ 27,348** | $ (11,839) | $ (9,055) |
| Items not requiring a current cash outlay: | | | |
| Depletion and amortization | **43,770** | 67,571 | 48,325 |
| Write-down of marketable securities | **1,079** | – | – |
| Deferred income taxes | **21,434** | (5,634) | (1,423) |
| Cash flow from operations | **93,631** | 50,098 | 37,847 |
| Change in non-cash operating working capital (Note 9) | | | |
| Accounts receivable | **(14,071)** | (4,825) | (3,168) |
| Other current assets | **(4)** | (468) | 324 |
| Accounts payable and accrued | **2,897** | 3,830 | 164 |
| | **82,453** | 48,635 | 35,167 |
| Financing activities: | | | |
| Issue of common shares | **1,560** | 50,321 | 437 |
| Purchase of common shares for cancellation | **(4,863)** | (80) | (5,902) |
| Increase in long-term debt | **10,000** | 5,000 | 40,000 |
| Decrease in long-term debt | **–** | (35,000) | – |
| Financing costs | **–** | (4,058) | – |
| | **6,697** | 16,183 | 34,535 |
| Net cash flows from operating and financing activities | **89,150** | 64,818 | 69,702 |
| Investing activities: | | | |
| Lease acquisition, exploration and development costs | **(102,701)** | (55,176) | (91,690) |
| Sale of producing properties | **–** | 155 | – |
| Purchase of producing gas and oil properties | **–** | – | (883) |
| | **(102,701)** | (55,021) | (92,573) |
| Purchase of other capital assets and other | **(182)** | (48) | (93) |
| Change in investing accounts payable and accrued | **8,083** | (994) | 6,652 |
| Investment in marketable securities | **(5,000)** | – | – |
| | **(99,800)** | (56,063) | (86,014) |
| Change in cash and short-term deposits | **(10,650)** | 8,755 | (16,312) |
| Cash and short-term deposits, beginning of year | **19,368** | 10,613 | 26,925 |
| Cash and short-term deposits, end of year | **$ 8,718** | $ 19,368 | $ 10,613 |
| Cash flow from operations per common share (Note 8): | | | |
| Basic | **$ 5.79** | $ 3.66 | $ 2.81 |
| Diluted(Note 1(i)) | **$ 4.99** | $ 3.22 | $ 2.51 |

# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

**(December 31, 2000, 1999 and 1998)**

## Chieftain International, Inc. and Subsidiary Companies *

We are engaged in natural gas and oil exploration, development and production primarily in the United States ("US") and also in the United Kingdom ("UK") sector of the North Sea. The Consolidated Financial Statements are expressed in US currency as most of our assets and operations are denominated in US dollars.

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

### (a) Accounting principles

Our financial statements are prepared in conformity with Canadian generally accepted accounting principles. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make informed judgements and estimates. Actual results may differ from those estimates. Material differences between Canadian and US accounting principles that affect us are referred to in Note 12, which provides the effects of the differences on earnings and balance sheet accounts.

### (b) Principles of consolidation

The Consolidated Financial Statements include our accounts and the accounts of our subsidiary companies, all of which are wholly-owned except for Chieftain International Funding Corp., a US subsidiary which in 1992 issued 2,726,700 preferred shares to the public. These preferred shares are convertible into common shares of Chieftain International, Inc. See Note 4.

Acquisitions of subsidiaries and businesses have been accounted for by the purchase method and accordingly only income or losses since date of acquisition are included in the Consolidated Statement of Income (Loss) and Deficit.

### (c) Marketable securities

Our interest in marketable securities is accounted for by the cost method. Application of the cost method results in the investment initially being recorded at cost and earnings therefrom are recognized only to the extent that dividends are received or are receivable. The amount of the investment is reduced by any dividends received in excess of our pro rata share of post-acquisition income.

### (d) Foreign currency translation

Canadian and other foreign currency amounts have been translated into US currency on the following bases: monetary assets and liabilities at the year-end rates of exchange; non-monetary assets and liabilities at historical exchange rates; and revenue and expenses at monthly average exchange rates during the year. Translation gains or losses are reflected in the Consolidated Statement of Income (Loss) and Deficit.

### (e) Financial assets and liabilities

Our financial instruments that are included in the Consolidated Balance Sheet are comprised of cash and short-term deposits, accounts receivable, marketable securities, all current liabilities and long-term debt. In each case, their fair value approximates the carrying amount reflecting their short-term or current rate nature. Cash and short-term deposits include minimum risk certificates guaranteed by a major Canadian bank and are purchased three months or less from maturity. Accounts receivable are subject to normal oil and natural gas industry credit risks. Marketable securities are subject to currency, market and liquidity risks: the shares trade in Canadian currency, share prices are volatile and timely divestiture may not be possible at share prices approximating fair value. Long-term debt is subject to normal floating interest rate risk.

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* Unless the context indicates another meaning, the terms "we", "us" and "our" refer to Chieftain International, Inc., a company organized under the laws of the Province of Alberta, Canada, and its subsidiaries.

### (f) Natural resource properties

We account for natural gas and oil properties in accordance with the Canadian guideline on full cost accounting.

Under this method, all costs associated with the acquisition, exploration and development of natural gas and oil properties are capitalized in cost centers on a country-by-country basis. Depletion is calculated using the unit-of-production method based on gross proved reserves (before royalties) and combining oil and natural gas on an energy equivalent basis, using the ratio of 1 barrel of oil = 6,000 cubic feet of natural gas. Future well abandonment and site restoration costs are included in the calculation of depletion expense and are based on current engineering estimates in accordance with current regulations and industry practices. Actual costs, when incurred, are charged against the abandonment cost accrual.

A ceiling test is applied to ensure that capitalized costs do not exceed estimated future net revenues less certain applicable costs. See Note 2.

### (g) Land, buildings and other equipment

Amortization is provided as follows:

| | Rate per annum | Method |
|---|---|---|
| Buildings | 5% | Straight-line |
| Furniture, office equipment and leasehold improvements | 10 - 20% | Straight-line |

Expenditures for renewals and betterments which materially increase the estimated useful life of buildings and equipment are capitalized; expenditures for repairs and maintenance are charged to income. Costs and accumulated amortization of assets retired or sold are removed from the asset and related accumulated amortization accounts; losses and gains thereon are included in the Consolidated Statement of Income (Loss) and Deficit as depletion and amortization.

### (h) Income taxes

Income taxes are recorded using the liability method of accounting. Applying this method, deferred income taxes are recognized, using applicable, enacted, or substantively enacted, income tax rates, for future income tax consequences attributable to differences between the financial statement carrying values and their respective income tax bases. The effect of a change in tax rates on deferred income tax assets and liabilities is included in income in the period that includes the enactment date. Deferred income tax assets are evaluated and if realization is considered “more likely than not”, no valuation allowance is provided.

### (i) Per share amounts

Effective with the fourth quarter of 2000, we retroactively adopted revised per share calculation methods which are required to be adopted no later than 2001 under Canadian generally accepted accounting principles. Consistent with the revision, we now include share options in diluted per share amounts, where dilutive, assuming that the share options are exercised using the treasury stock method.

The retroactive application of this policy had the effects of increasing our diluted income per common share by \$0.05 in 2000 and increasing our diluted cash flow from operations per common share by \$0.22, \$0.15 and \$0.08 in 2000, 1999 and 1998, respectively. All relevant amounts for prior periods have been restated for consistency and comparability.

## 2. NATURAL RESOURCE PROPERTIES

The following weighted average December 31 field prices were used in the determination of our US future net revenues for purposes of the ceiling test:

| As at December 31, | 2000 | 1999 | 1998 |
|---|---|---|---|
| Oil and ngls *(per barrel)* | **$ 24.60** | $ 20.40 | $ 12.27 |
| Natural gas *(per thousand cubic feet ("mcf"))* | **$ 9.68** | $ 2.51 | $ 2.15 |

A field price of $3.65 (1999 - $0.99; 1998 - $1.74) per mcf was used in the determination of our UK future net revenues for purposes of the ceiling test.

There is uncertainty as to the prices at which natural gas and oil produced by us may be sold in the future.

The application of the ceiling test to US property carrying costs at December 31, 1998, using the $12.27 per barrel average oil and natural gas liquids ("ngls") price received by us during the year and the $2.15 per mcf December 31, 1998 natural gas price, required no write-down. At December 31, 1998, a write-down of $10,614,000, after providing for tax recoveries of $5,842,000, would have been required had prices as of that date, $2.15 per mcf for natural gas and $9.72 per barrel for oil and ngls, been used. At December 31, 1999 an impairment provision of $6,310,000 (1998 - $2,849,000), after providing for tax recoveries of $5,083,000 (1998 - $2,295,000), was recorded in respect of the Libyan concessions which resulted in all Libyan costs being written off as of that date. At December 31, 1999, a write-down of $2,654,000 (1998 - $609,000), after providing for tax recoveries of $2,139,000 (1998 - $491,000), was recorded in respect of the UK properties.

Depletion rates per physical unit of US production are as follows:

| | Natural Gas | Oil and ngls |
|---|---|---|
| | *(per mcf)* | *(per barrel)* |
| Year ended December 31, 1998 | $ 1.16 | $ 6.97 |
| Year ended December 31, 1999 | $ 1.25 | $ 7.50 |
| **Year ended December 31, 2000** | **$ 1.23** | **$ 7.36** |

The depletion rate per physical unit of UK natural gas production was $0.51 per mcf for the year ended December 31, 2000 (1999 - $1.24; 1998 - $0.81).

At December 31, 1998, Libyan property carrying costs of $9.9 million were excluded from depletion calculations pending evaluation.

General and administrative costs relating directly to lease acquisition, exploration and development activities have been capitalized as follows:

| Year ended December 31, | 2000 | 1999 | 1998 |
|---|---|---|---|
| *(in thousands)* | | | |
| Lease acquisition | **$ 1,849** | $ 765 | $ 857 |
| Exploration | **2,660** | 1,581 | 1,740 |
| Development | **1,547** | 1,601 | 1,715 |
| | **$ 6,056** | $ 3,947 | $ 4,312 |

## 3. REVOLVING CREDIT AND LONG-TERM DEBT

In 1997 we arranged an unsecured revolving credit facility with a syndicate of banks. The facility, in the amount of $70 million (1999 - $100 million)or the Canadian dollar equivalent, is fully revolving for 364 day periods with extensions at the option of the lenders upon our request. If not extended, the facility converts to term loans repayable over a period not exceeding four years. Advances under the facility bear interest at Canadian prime rate, US base rate, Bankers' Acceptance rate or LIBOR plus applicable margins. Certain financial tests are required to be met quarterly. Under this facility, $20 million was utilized at December 31, 2000 (1999 - $10 million), carrying a weighted average interest rate of 7.63% (1999 - 7.00%).

## 4. PREFERRED SHARES OF A SUBSIDIARY

Chieftain International Funding Corp. ("Funding"), a subsidiary of Chieftain International (U.S.) Inc., sold 2,726,700 shares of $1.8125 cumulative convertible redeemable preferred shares at $25.00 per share in a 1992 public offering in the US. The preferred shares are redeemable, at the option of Funding, at $25.2014 per share during 2001 and $25.00 per share after December 31, 2001, plus accumulated and unpaid dividends. Each preferred share has a liquidation preference of $25.00 and is convertible at any time into 1.25 Common Shares of Chieftain International, Inc. at the option of the holder.

## 5. SHARE CAPITAL

### (a) Common shares

| Year ended December 31, | 2000 | | 1999 | | 1998 | |
|---|---|---|---|---|---|---|
| | **Number of shares** | **Share Capital Account** | Number of shares | Share Capital Account | Number of shares | Share Capital Account |
| *(in thousands except number of shares)* | | | | | | |
| Balance, beginning of year | **16,224,059** | **$ 237,076** | 13,355,891 | $ 189,108 | 13,622,375 | $ 192,845 |
| Share options exercised | **105,368** | **1,560** | 668 | 9 | 28,216 | 437 |
| Shares purchased and cancelled* | **(228,600)** | **(3,341)** | (7,500) | (106) | (294,700) | (4,174) |
| Shares issued for cash** | **–** | **–** | 2,875,000 | 48,065 | – | – |
| Balance, end of year | **16,100,827** | **$ 235,295** | 16,224,059 | $ 237,076 | 13,355,891 | $ 189,108 |

*Pursuant to normal course issuer bid.
**Reduced by costs of issue of $4,058, less related deferred taxes of $1,811.

In the fourth quarter of 1999, we sold 2,875,000 common shares by way of a public offering in the US at $17.50 per share.

### (b) Common shares reserved

At December 31, 2000, 1,394,632 (1999 - 1,130,207; 1998 - 1,130,875) of our authorized but unissued common shares were reserved for issuance under the Share Option Plan. See Note 5(d).

We have reserved 3,408,375 common shares for issuance pursuant to the conversion provisions of the preferred shares of a subsidiary. See Note 4.

### (c) Contributed surplus

Contributed surplus represents the excess of original net issue price over purchase price of shares purchased and cancelled pursuant to successive issuer bids.

## (d) Share Option Plan (the "Plan")

The Plan provides for the granting of options to employees, directors and consultants to purchase our common shares. Each option expires not later than ten years from the date it was granted. Options are exercisable as to one-third of the granted amount on or after each of the first three anniversaries of the date of grant. The option price for shares in respect of which an option is granted under the Plan is not less than the market price on the date of grant and, therefore, no compensation expense is recognized. Proceeds arising from the exercise of share options are credited to share capital. At December 31, 2000 options were outstanding to 60 participants in the Plan.

The following is a summary of activity related to the Plan for the years ended December 31, 2000, 1999 and 1998.

| Year ended December 31, | **2000** | | 1999 | | 1998 | |
|---|---|---|---|---|---|---|
| | **Number of Shares** | **Weighted Average Option Price** | Number of Shares | Weighted Average Option Price | Number of Shares | Weighted Average Option Price |
| Outstanding at beginning of year | **1,119,189** | **$ 16.58** | 1,083,857 | $ 16.74 | 1,057,673 | $ 16.47 |
| Granted | **233,000** | **20.26** | 180,000 | 13.44 | 65,000 | 21.08 |
| Exercised | **(105,368)** | **14.81** | (668) | 13.63 | (28,216) | 15.49 |
| Forfeited | **(2,000)** | **21.32** | (4,000) | 22.54 | (10,600) | 20.07 |
| Expired | **–** | **–** | (140,000) | 13.61 | – | – |
| Outstanding at end of year | **1,244,821** | **17.41** | 1,119,189 | 16.58 | 1,083,857 | 16.74 |
| Options exercisable at year-end | **870,155** | | 824,521 | | 869,858 | |

The following table summarizes information about options outstanding at December 31, 2000.

| | Options Outstanding | | | Options Exercisable | |
|---|---|---|---|---|---|
| Range of Option Price | Number of Shares | Weighted Average Remaining Contractual Life | Weighted Average Option Price | Number of Shares | Weighted Average Option Price |
| $ 11.43 – 15.38 | 620,287 | 5.1 years | $ 14.18 | 510,287 | $ 14.43 |
| 18.00 – 20.88 | 361,334 | 7.2 years | 19.81 | 115,001 | 19.21 |
| 20.94 – 23.75 | 263,200 | 6.6 years | 21.74 | 244,867 | 21.69 |
| | 1,244,821 | | | 870,155 | |

## 6. INTEREST AND OTHER REVENUE

Interest and other revenue for 2000 included non-recurring revenue of $1.3 million arising from the Libyan venture which was terminated in the second quarter of 1999. Under the terms of the concession, the Libyan National Oil Company ("NOC") reimbursed us and our partners in kind for NOC's share of production test expenditures. The non-recurring revenue resulted from the increase in oil prices between the time when production test expenditures were incurred and the time when reimbursement was effected.

In 1998, interest and other revenue included $1.6 million awarded by the courts pursuant to a successful claim for recovery of excess transportation charges incurred from 1990 through 1997. The award comprises transportation charges, legal fees and judgement interest of $1,129,000, $282,000 and $189,000, respectively.

## 7. INCOME TAXES

Income tax expense is made up of the following components:

| Year ended December 31, | 2000 | | 1999 | | 1998 | |
|---|---|---|---|---|---|---|
| | **Canada** | **US** | Canada | US | Canada | US |
| *(in thousands)* | | | | | | |
| Income (loss) before income taxes and dividends on preferred shares of a subsidiary | **$ 1,043** | **$ 52,774** | $ (18,254) | $ 5,734 | $ (6,829) | $ 1,307 |
| Income taxes (recovery) | | | | | | |
| Current | **$ –** | **$ 93** | $ 11 | $ – | $ 14 | $ – |
| Deferred | **2,890** | **18,544** | (7,643) | 2,009 | (1,740) | 317 |
| | **$ 2,890** | **$ 18,637** | $ (7,632) | $ 2,009 | $ (1,726) | $ 317 |

The actual tax rate differs from the expected tax rate for the following reasons:

| Year ended December 31, | 2000 | 1999 | 1998 |
|---|---|---|---|
| *(in thousands)* | | | |
| Tax at statutory rate of 44.62% *(Combined Canadian Federal and provincial rate)* | **$ 24,013** | $ (5,587) | $ (2,465) |
| Add (deduct) the effect of: | | | |
| Lower income tax rate on earnings of US subsidiaries | **(4,766)** | (496) | (81) |
| Canadian income tax on exchange loss which is eliminated upon consolidation | **426** | 909 | 631 |
| Reduction in value of deferred tax assets resulting from reduction in future Canadian rate | **1,318** | – | – |
| Other | **536** | (449) | 506 |
| Tax at effective rate | **$ 21,527** | $ (5,623) | $ (1,409) |
| Effective tax rate | **40.0 %** | 44.9 % | 25.5 % |

Temporary differences comprising the deferred tax assets (liabilities) are as follows:

| As at December 31, | 2000 | | | 1999 | | |
|---|---|---|---|---|---|---|
| | **Canada** | **US** | **Total** | Canada | US | Total |
| *(in thousands)* | | | | | | |
| Deferred tax assets | | | | | | |
| Depletion and amortization | **$ 8,588** | **$ –** | **$ 8,588** | $ 10,679 | $ – | $ 10,679 |
| Financing costs | **1,254** | **–** | **1,254** | 2,005 | – | 2,005 |
| Loss carryforwards | **681** | **26,656** | **27,337** | 1,461 | 26,645 | 28,106 |
| Other | **1,223** | **14** | **1,237** | 491 | 4 | 495 |
| | **11,746** | **26,670** | **38,416** | 14,636 | 26,649 | 41,285 |
| Deferred tax liabilities | | | | | | |
| Depletion and amortization | **–** | **(60,907)** | **(60,907)** | – | (42,342) | (42,342) |
| Net deferred tax assets (liabilities) | **$ 11,746** | **$ (34,237)** | **$ (22,491)** | $ 14,636 | $ (15,693) | $ (1,057) |

At December 31, 2000 our net operating tax losses carried forward are summarized in the following table. We are of the opinion that the tax benefit of these tax losses will be realized.

| Year of expiry | Canada | US |
|---|---|---|
| *(in thousands)* | | |
| 2003 | $ 1,492 | $ – |
| 2005 | 239 | 6,119 |
| 2007 | – | 2,835 |
| 2009 | – | 6,139 |
| 2010 | – | 18,007 |
| 2011 | – | 3,773 |
| 2012 | – | 2,090 |
| 2018 | – | 16,088 |
| 2019 | – | 19,221 |
| 2020 | – | 814 |
| Total | $ 1,731 | $ 75,086 |

## 8. PER SHARE AMOUNTS

Basic net income (loss) per common share is calculated by dividing net income (loss) applicable to common shares by the weighted average number of common shares outstanding during the year. Diluted income (loss) per common share is calculated to give effect to share options and shares issuable on conversion of preferred shares.

| Year ended December 31, *(in thousands)* | **2000** | 1999 | 1998 |
|---|---|---|---|
| Net income (loss) applicable to common shares | **$ 27,348** | $ (11,839) | $ (9,055) |
| Dividends paid on preferred shares of a subsidiary | **4,942** | – | – |
| Diluted net income (loss) | **$ 32,290** | $ (11,839) | $ (9,055) |

| Year ended December 31, *(shares in thousands)* | **2000** | 1999 | 1998 |
|---|---|---|---|
| Basic weighted average number of common shares outstanding | **16,183** | 13,701 | 13,480 |
| Effect of dilutive securities | | | |
| Exercise of share options | **154** | – | – |
| Conversion of preferred shares | **3,408** | – | – |
| Diluted weighted average number of common shares outstanding | **19,745** | 13,701 | 13,480 |

Basic cash flow from operations per common share is calculated by dividing cash flow from operations by the weighted average number of common shares outstanding during the year. Diluted cash flow from operations per common share is calculated to give effect to share options and shares issuable on conversion of preferred shares.

| Year ended December 31, *(in thousands)* | **2000** | 1999 | 1998 |
|---|---|---|---|
| Cash flow from operations | **$ 93,631** | $ 50,098 | $ 37,847 |
| Dividends paid on preferred shares of a subsidiary | **4,942** | 4,942 | 4,942 |
| Diluted cash flow from operations | **$ 98,573** | $ 55,040 | $ 42,789 |

| Year ended December 31, *(shares in thousands)* | **2000** | 1999 | 1998 |
|---|---|---|---|
| Basic weighted average number of common shares outstanding | **16,183** | 13,701 | 13,480 |
| Effect of dilutive securities | | | |
| Exercise of share options | **154** | – | 163 |
| Conversion of preferred shares | **3,408** | 3,408 | 3,408 |
| Diluted weighted average number of common shares outstanding | **19,745** | 17,109 | 17,051 |

## 9. SUPPLEMENTAL CASH FLOW INFORMATION

Net cash outflows for (inflows from) income taxes were $211,000, $(12,000) and $14,000 for the years 2000, 1999 and 1998, respectively. Cash outflows for long-term debt interest were $1,032,000, $2,601,000 and $628,000 in 2000, 1999 and 1998, respectively.

## 10. PENSION COSTS AND OBLIGATIONS

We contributed $178,416, $145,418 and $145,300 for 2000, 1999 and 1998, respectively, to defined contribution pension plans. Under a supplementary defined contribution pension plan established in 1991, costs of $209,484, $216,401 and $198,294 for 2000, 1999 and 1998, respectively, and the related liability are recorded in the accounts.

We have established no other post-employment benefit plans.

## 11. SEGMENTED INFORMATION

We have a single reportable segment with activities as explained in the preamble to the Notes. Production revenue, after royalties, all of which arises from external customers, is attributed to the country in which the underlying production occurred. Most of the US natural gas, oil and ngls we produce are marketed by a single aggregator. Production revenues, after royalties, associated with the aggregator were $90,842,000 (1999 - $59,665,000; 1998 - $46,340,000). As at December 31, 2000, we had entered into natural gas forward contracts with the aggregator. The forward contracts are for the physical delivery of, during the first nine months of the following year, natural gas volumes totalling 7.1 billion cubic feet ("bcf") (1999 - 6.1 bcf), at an average price of $4.86 per mcf (1999 - $2.49 per mcf). Our oil production from the Aneth and Ratherford Units in the Four Corners area of Utah is sold under successive term contracts to a regional refiner. Production revenues, after royalties, associated with sales to the regional refiner were $14,188,000 (1999 - $9,710,000; 1998 - $8,207,000). At December 31, 1999, we had entered into an oil forward contract with the regional refiner for the physical delivery, in 2000, of oil volumes of 90,000 barrels at an average price of $19.00 per barrel. We believe that alternative marketing arrangements would be readily available for our natural gas, oil and ngls.

| *(in thousands)* | **2000** | 1999 | 1998 |
|---|---|---|---|
| Production revenue, after royalties | | | |
| US | **$ 113,005** | $ 71,487 | $ 56,199 |
| UK | **3,987** | 3,582 | 4,411 |
| Libya | **–** | 297 | 1,005 |
| Total production revenue, after royalties | **116,992** | 75,366 | 61,615 |
| Interest and other revenue | **2,881** | 1,081 | 2,776 |
| Total revenue | **$ 119,873** | $ 76,447 | $ 64,391 |
| Net capital assets | | | |
| US | **$ 336,114** | $ 274,904 | $ 267,020 |
| UK | **1,013** | 1,994 | 11,337 |
| Canada and other | **276** | 251 | 285 |
| Libya | **–** | – | 9,835 |
| | **$ 337,403** | $ 277,149 | $ 288,477 |

## 12. US ACCOUNTING PRINCIPLES

### (a) Full cost accounting

US full cost accounting rules differ materially from the Canadian full cost accounting guidelines we follow. In determining the limitation on carrying values, US rules require the discounting of future net revenues at 10%, and Canadian guidelines require the use of undiscounted future net revenues and the deduction of estimated future administrative and financing costs. During 1999 and 1998, impairment adjustments would have been required under US accounting rules. The quarterly test required by US accounting rules, using a March 31, 1999 UK natural gas price of $0.84 per mcf to determine future net revenues, would have resulted in a write-down of UK property carrying costs at March 31, 1999 of $7.1 million and, after providing for tax recoveries of $3.1 million, a net charge to operations of $4.0 million. Using December 31, 1998 US natural gas and oil prices of $2.15 per mcf and $9.72 per barrel to determine future net revenues would have resulted in a write-down of US property carrying costs of $65.5 million and, after providing for tax recoveries of $22.9 million, a net charge to operations of $42.6 million at December 31, 1998. Using June 30, 1998 US prices of $2.09 per mcf and $12.40 per barrel to determine future net revenues would have resulted in a write-down of US property carring costs of $24.7 million and, after providing for tax recoveries of $8.6 million, a net charge to operations of $16.1 million at June 30, 1998. Such write-downs would result in reduced depletion expense, under US rules, for subsequent periods. In 1999, under Canadian guidelines the test resulted in a write-down of UK property carrying costs of $4.8 million (1998 - $1.1 million) and, after providing for tax recoveries of $2.1 million (1998 - $0.5 million), a net charge to operations of $2.7 million (1998 - $0.6 million) at December 31; no corresponding write-downs were required under US accounting rules.

### (b) Effect on earnings

The effect on consolidated earnings of the differences between Canadian and US accounting principles is summarized as follows:

| Year ended December 31, | **2000** | 1999 | 1998 |
|---|---|---|---|
| *(in thousands except per share amounts)* | | | |
| Net income (loss) applicable to common shares, as reported | **$ 27,348** | $ (11,839) | $ (9,055) |
| Additional depletion difference | **–** | (2,311) | (89,153) |
| | **27,348** | (14,150) | (98,208) |
| Reduction in depletion expense | **11,042** | 17,623 | 4,235 |
| Reduction (increase) in deferred tax provision | **(2,657)** | (5,440) | 30,010 |
| Net income (loss) applicable to common shares under US accounting principles | **$ 35,733** | $ (1,967) | $ (63,963) |
| Net income (loss) per common share under US accounting principles: | | | |
| Basic | **$ 2.21** | $ (0.14) | $ (4.75) |
| Diluted | **$ 2.06** | $ (0.14) | $ (4.75) |
| Diluted common shares outstanding | **19,745** | 13,701 | 13,480 |

### (c) Effect on balance sheet

The effect on the Consolidated Balance Sheet of the differences between Canadian and US accounting principles is as follows:

| As at December 31, | 2000 | | 1999 | |
|---|---|---|---|---|
| | **As Reported** | **Under US Accounting Principles** | As Reported | Under US Accounting Principles |
| *(in thousands)* | | | | |
| Net capital assets | **$ 337,403** | **$ 260,797** | $ 277,149 | $ 189,501 |
| Deferred tax - asset | **11,746** | **13,675** | 14,636 | 30,238 |
| Deferred tax - liability | **34,237** | **7,528** | 15,693 | – |
| Deficit | **(3,552)** | **(51,520)** | (29,404) | (85,757) |

Additionally for US reporting purposes, the preferred shares shown as shareholders' equity in these consolidated financial statements would be shown outside the equity section.

### (d) Income tax disclosures

Provisions for deferred income taxes are as follows:

| Year ended December 31, | 2000 | | 1999 | | 1998 | |
|---|---|---|---|---|---|---|
| | **Canada** | **US** | Canada | US | Canada | US |
| *(in thousands)* | | | | | | |
| Income (loss) before income taxes and dividends on preferred shares of a subsidiary | **$ 1,648** | **$ 63,211** | $ (17,492) | $ 20,284 | $ (5,002) | $ (85,440) |
| Provision for deferred income taxes | **$ 1,842** | **$ 22,249** | $ (7,248) | $ 7,054 | $ (921) | $ (30,512) |

The provision for income taxes differs from the amount of income tax determined by applying the Canadian statutory rate to pre-tax income before dividends paid on preferred shares of a subsidiary, as a result of the following:

| Year ended December 31, | 2000 | 1999 | 1998 |
|---|---|---|---|
| *(in thousands)* | | | |
| Tax at statutory Canadian rate of 44.62% | **$ 28,940** | $ 1,247 | $ (40,355) |
| Lower income tax rate on earnings of US subsidiaries | **(5,717)** | (1,823) | 7,830 |
| Canadian income tax on exchange loss which is eliminated upon consolidation | **426** | 909 | 631 |
| Exchange revaluation of Canadian deferred tax assets | **515** | (553) | 280 |
| Other | **20** | 37 | 195 |
| Tax at effective rate | **$ 24,184** | $ (183) | $ (31,419) |
| Effective tax rate | **37.3 %** | (6.6) % | 34.7 % |

Temporary differences comprising the deferred tax assets (liabilities) are as follows:

| As at December 31, | 2000 | | | 1999 | | |
|---|---|---|---|---|---|---|
| | **Canada** | **US** | **Total** | Canada | US | Total |
| *(in thousands)* | | | | | | |
| Deferred tax assets | | | | | | |
| Depletion and amortization | **$ 10,155** | **$ –** | **$ 10,155** | $ 11,561 | $ – | $ 11,561 |
| Financing costs | **1,374** | **–** | **1,374** | 2,005 | – | 2,005 |
| Loss carryforwards | **772** | **26,656** | **27,428** | 1,461 | 26,645 | 28,106 |
| Other | **1,374** | **15** | **1,389** | 490 | 5 | 495 |
| | **13,675** | **26,671** | **40,346** | 15,517 | 26,650 | 42,167 |
| Deferred tax liabilities | | | | | | |
| Depletion and amortization | **–** | **(34,199)** | **(34,199)** | – | (11,929) | (11,929) |
| Net deferred tax assets (liabilities) | **$ 13,675** | **$ (7,528)** | **$ 6,147** | $ 15,517 | $ 14,721 | $ 30,238 |

## (e) Stock-based compensation

We apply the intrinsic value method prescribed by APB Opinion 25 and related interpretations in accounting for share option transactions. Accordingly, no compensation cost is recognized in the accounts. US accounting principles require disclosure of the impact on earnings and earnings per share of the value of options granted after 1994, calculated in accordance with FAS 123.

Such impact, using fair values of $11.38, $7.75 and $10.61 for options granted in 2000, 1999 and 1998, respectively, would approximate the following pro forma amounts.

| Year ended December 31, | **2000** | 1999 | 1998 |
|---|---|---|---|
| *(in thousands except per share amounts)* | | | |
| Compensation costs, net of tax | **$ 1,361** | $ 1,255 | $ 1,502 |
| Net income (loss) applicable to common shares | | | |
| As reported | **$ 35,733** | $ (1,967) | $ (63,963) |
| Pro forma | **$ 34,372** | $ (3,222) | $ (65,465) |
| Net income (loss) per common share | | | |
| Basic | | | |
| As reported | **$ 2.21** | $ (0.14) | $ (4.75) |
| Pro forma | **$ 2.12** | $ (0.24) | $ (4.86) |
| Diluted | | | |
| As reported | **$ 2.06** | $ (0.14) | $ (4.75) |
| Pro forma | **$ 2.01** | $ (0.24) | $ (4.86) |

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

| Year ended December 31, | **2000** | 1999 | 1998 |
|---|---|---|---|
| Risk free interest rate | **6.48 %** | 5.68 % | 5.64 % |
| Expected lives *(years)* | **10** | 10 | 10 |
| Expected volatility | **29 %** | 28 % | 25 % |
| Dividends | **None** | None | None |

## (f) Recent accounting pronouncements

FAS 133, Accounting for Derivative Instruments and Hedging Activities, as amended by FAS 138, is first effective for our 2001 fiscal year. FAS 133 currently has no affect on us as our derivative instruments qualify for the normal purchases and normal sales exception.

## Chieftain International, Inc. and Subsidiary Companies
## December 31, 2000

(Unaudited)

### Reserve Information

Reports prepared by Netherland, Sewell & Associates, Inc. as to our US reserves and by ourselves as to the UK reserves, estimate the total proved reserves owned by us, before and after royalty deductions, as follows:

| | Natural Gas – mmcf | | | Oil and ngls – mbbls * |
|---|---|---|---|---|
| **Total Proved Reserves - Before Royalty Deductions** | US | UK | Total | US |
| December 31, 1998 | 148,954 | 10,110 | 159,064 | 15,200 |
| Purchase of producing properties | – | – | – | – |
| Revision of previous estimates | (5,635) | (151) | (5,786) | 1,602 |
| Extensions, discoveries and other additions | 64,127 | – | 64,127 | 2,152 |
| Sale of proved properties | – | – | – | – |
| Production | (27,536) | (3,583) | (31,119) | (1,644) |
| December 31, 1999 | 179,910 | 6,376 | 186,286 | 17,310 |
| **Purchase of producing properties** | **2,741** | **–** | **2,741** | **99** |
| **Revision of previous estimates** | **29,936** | **1,549** | **31,485** | **(870)** |
| **Extensions, discoveries and other additions** | **41,280** | **–** | **41,280** | **239** |
| **Sale of proved properties** | **–** | **–** | **–** | **–** |
| **Production** | **(26,016)** | **(1,940)** | **(27,956)** | **(1,464)** |
| **December 31, 2000** | **227,851** | **5,985** | **233,836** | **15,314** |

| | Natural Gas – mmcf | | | Oil and ngls – mbbls * |
|---|---|---|---|---|
| **Total Proved Reserves - After Royalty Deductions** | US | UK | Total | US |
| December 31, 1998 | 118,963 | 10,110 | 129,073 | 13,107 |
| Purchase of producing properties | – | – | – | – |
| Revision of previous estimates | (4,707) | (151) | (4,858) | 1,475 |
| Extensions, discoveries and other additions | 51,251 | – | 51,251 | 1,753 |
| Sale of proved properties | – | – | – | – |
| Production | (21,950) | (3,583) | (25,533) | (1,389) |
| December 31, 1999 | 143,557 | 6,376 | 149,933 | 14,946 |
| **Purchase of producing properties** | **1,839** | **–** | **1,839** | **66** |
| **Revision of previous estimates** | **22,393** | **1,549** | **23,942** | **(875)** |
| **Extensions, discoveries and other additions** | **34,019** | **–** | **34,019** | **196** |
| **Sale of proved properties** | **–** | **–** | **–** | **–** |
| **Production** | **(20,931)** | **(1,940)** | **(22,871)** | **(1,235)** |
| **December 31, 2000** | **180,877** | **5,985** | **186,862** | **13,098** |

* 19,100 (1999 - 20,100) barrels of natural gas liquids, before and after royalty deductions, associated with the UK gas reserves are not included in this table.

(Unaudited)

| Proved Developed Producing Reserves - Before Royalty Deductions | Natural Gas – mmcf | | | Oil and ngls – mbbls |
|---|---|---|---|---|
| | US | UK | Total | US |
| December 31, 1998 | 70,082 | 10,108 | 80,190 | 5,430 |
| December 31, 1999 | 63,822 | 6,376 | 70,198 | 7,447 |
| **December 31, 2000** | **98,625** | **5,985** | **104,610** | **6,893** |

| Proved Developed Producing Reserves - After Royalty Deductions | Natural Gas – mmcf | | | Oil and ngls – mbbls |
|---|---|---|---|---|
| | US | UK | Total | US |
| December 31, 1998 | 55,418 | 10,108 | 65,526 | 4,739 |
| December 31, 1999 | 50,531 | 6,376 | 56,907 | 6,580 |
| **December 31, 2000** | **77,699** | **5,985** | **83,684** | **6,002** |

(Unaudited)

## Results of Operations for Gas and Oil Producing Activities

| Year ended December 31, *(in thousands)* | **2000** | 1999 | 1998 |
|---|---|---|---|
| US | | | |
| Revenue - net of royalties | **$ 113,005** | $ 71,487 | $ 56,199 |
| Production costs | **(16,861)** | (18,128) | (15,675) |
| Depletion and amortization | **(42,680)** | (46,796) | (39,460) |
| Results of operations before income taxes | **53,464** | 6,563 | 1,064 |
| Income tax (expense) recovery | **(18,966)** | (2,300) | (333) |
| Results of operations after income taxes | **34,498** | 4,263 | 731 |
| UK | | | |
| Revenue - net of royalties | **3,987** | 3,582 | 4,411 |
| Production costs | **(256)** | (338) | (964) |
| Depletion and amortization | **(1,016)** | (9,304) | (3,646) |
| Results of operations before income taxes | **2,715** | (6,060) | (199) |
| Income tax (expense) recovery | **(1,088)** | 2,624 | 117 |
| Results of operations after income taxes | **1,627** | (3,436) | (82) |
| Libya | | | |
| Revenue - net of royalties | **–** | 297 | 1,005 |
| Production costs | **–** | (631) | (1,041) |
| Depletion and amortization | **–** | (11,393) | (5,144) |
| Results of operations before income taxes | **–** | (11,727) | (5,180) |
| Income tax (expense) recovery | **–** | 5,233 | 2,312 |
| Results of operations after income taxes | **–** | (6,494) | (2,868) |
| Total | | | |
| Revenue - net of royalties | **116,992** | 75,366 | 61,615 |
| Production costs | **(17,117)** | (19,097) | (17,680) |
| Depletion and amortization | **(43,696)** | (67,493) | (48,250) |
| Results of operations before income taxes | **56,179** | (11,224) | (4,315) |
| Income tax (expense) recovery | **(20,054)** | 5,557 | 2,096 |
| Results of operations after income taxes | **$ 36,125** | $ (5,667) | $ (2,219) |

(Unaudited)

## Capitalized Costs Relating to Gas and Oil Exploration and Production Activities

| December 31, *(in thousands)* | 2000 | 1999 | 1998 |
|---|---|---|---|
| Proved gas and oil properties | **$ 636,939** | $ 550,097 | $ 475,902 |
| Unproved gas and oil properties | **73,163** | 57,304 | 76,478 |
| | **710,102** | 607,401 | 552,380 |
| Accumulated depletion | **(383,482)** | (339,786) | (266,066) |
| Net capitalized costs | **$ 326,620** | $ 267,615 | $ 286,314 |

## Costs Incurred in Gas and Oil Property Acquisition, Exploration and Development Activities

| Year ended December 31, *(in thousands)* | 2000 | 1999 | 1998 |
|---|---|---|---|
| Property acquisition costs: | | | |
| US | **$ 7,789** | $ 5,352 | $ 7,903 |
| UK | **33** | 28 | 115 |
| | **7,822** | 5,380 | 8,018 |
| Purchase of producing properties: | | | |
| US | **–** | – | 883 |
| Sale of producing properties: | | | |
| US | **–** | (155) | – |
| Exploration costs: | | | |
| US | **57,926** | 28,753 | 43,317 |
| UK | **9** | 9 | 72 |
| Other foreign | **–** | 1,531 | 606 |
| | **57,935** | 30,293 | 43,995 |
| Development costs: | | | |
| US | **36,943** | 19,542 | 39,606 |
| UK | **1** | (39) | 71 |
| | **36,944** | 19,503 | 39,677 |
| Total | **$ 102,701** | $ 55,021 | $ 92,573 |

(Unaudited)

## Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil, Natural Gas Liquids and Natural Gas Reserves

The following standardized measure of discounted future net cash flow was computed in accordance with Financial Accounting Standards Board Statement 69 using year-end prices and costs, and year-end statutory tax rates. Royalty deductions were based on laws, regulations and contracts existing at the end of each period. No values are given to unproved properties or to probable reserves that may be recovered from proved properties.

The inexactness associated with estimating reserve quantities, future production streams and future development and production expenditures, together with the assumptions applied in valuing future production, substantially diminish the reliability of this data. The values so derived are not considered to be estimates of fair market value. **We therefore caution against simplistic use of this information.**

| December 31, | **2000** | 1999 | 1998 |
|---|---|---|---|
| *(in thousands)* | | | |
| US | | | |
| Future cash inflows | **$2,073,021** | $ 665,306 | $ 382,771 |
| Future production costs | **(203,058)** | (180,948) | (116,976) |
| Future development costs | **(120,262)** | (83,476) | (60,203) |
| Future income tax expense | **(539,413)** | (63,590) | – |
| Future net cash flows | **1,210,288** | 337,292 | 205,592 |
| Ten percent annual discount for estimated timing of cash flows | **(371,192)** | (114,871) | (62,089) |
| Standardized measure of discounted future net cash flows | **839,096** | 222,421 | 143,503 |
| UK | | | |
| Future cash inflows | **22,809** | 11,826 | 19,349 |
| Future production costs | **(3,735)** | (8,261) | (7,483) |
| Future development costs | **(1,469)** | (1,397) | (1,457) |
| Future income tax expense | **(4,441)** | – | – |
| Future net cash flows | **13,164** | 2,168 | 10,409 |
| Ten percent annual discount for estimated timing of cash flows | **(2,795)** | (56) | (1,404) |
| Standardized measure of discounted future net cash flows | **10,369** | 2,112 | 9,005 |
| Total | | | |
| Future cash inflows | **2,095,830** | 677,132 | 402,120 |
| Future production costs | **(206,793)** | (189,209) | (124,459) |
| Future development costs | **(121,731)** | (84,873) | (61,660) |
| Future income tax expense | **(543,854)** | (63,590) | – |
| Future net cash flows | **1,223,452** | 339,460 | 216,001 |
| Ten percent annual discount for estimated timing of cash flows | **(373,987)** | (114,927) | (63,493) |
| Standardized measure of discounted future net cash flows | **$ 849,465** | $ 224,533 | $ 152,508 |

(Unaudited)

The following table sets out principal sources of change in the standardized measure of discounted future net cash flows during the respective periods.

| Year ended December 31, *(in thousands)* | 2000 | 1999 | 1998 |
|---|---|---|---|
| Sales of oil, ngls and natural gas produced, net of production costs | **$ (102,732)** | $ (61,192) | $ (45,231) |
| Net change in prices and production costs | **710,398** | 83,559 | (79,471) |
| Extensions and discoveries, less related costs | **224,214** | 83,248 | 30,159 |
| Purchase of producing properties | **10,792** | – | 2,793 |
| Sales of producing properties | **–** | – | – |
| Development costs incurred during the period | **27,828** | 9,734 | 23,131 |
| Revisions of previous quantity estimates | **87,934** | (8,441) | (17,191) |
| Accretion of discount | **22,453** | 15,251 | 19,958 |
| Net change in income taxes | **(330,636)** | (41,941) | 38,739 |
| Changes in estimated future development costs | **(39,238)** | (23,126) | (16,421) |
| Other | **13,919** | 14,933 | (3,531) |
| Net increase (decrease) | **624,932** | 72,025 | (47,065) |
| Beginning of year | **224,533** | 152,508 | 199,573 |
| End of year | **$ 849,465** | $ 224,533 | $ 152,508 |

(Unaudited)

## Quarterly Information

| | 2000 Quarter Ended | | | | 1999 Quarter Ended | | | |
|---|---|---|---|---|---|---|---|---|
| | **Mar 31** | **Jun 30** | **Sep 30** | **Dec 31** | Mar 31 | Jun 30 | Sep 30 | Dec 31 |
| *(in thousands except per share amounts)* | | | | | | | | |
| **Financial** | | | | | | | | |
| Revenue | **$ 21,224** | **$ 24,436** | **$ 32,996** | **$ 41,217** | $ 13,218 | $ 17,543 | $ 22,763 | $ 22,923 |
| Cash flow from operations | **14,655** | **17,949** | **26,475** | **34,552** | 6,767 | 10,576 | 16,260 | 16,495 |
| Per share - basic | **0.90** | **1.11** | **1.63** | **2.15** | 0.51 | 0.79 | 1.22 | 1.12 |
| - diluted * | **0.81** | **0.97** | **1.40** | **1.81** | 0.48 | 0.70 | 1.03 | 0.97 |
| Gross profit | **5,376** | **8,968** | **16,352** | **23,121** | (4,169) | (12,491) | 3,874 | 266 |
| Net income (loss) | **2,105** | **3,912** | **8,940** | **12,391** | (3,860) | (8,507) | 1,282 | (754) |
| Per share - basic | **0.13** | **0.24** | **0.55** | **0.77** | (0.29) | (0.64) | 0.10 | (0.05) |
| - diluted * | **0.13** | **0.24** | **0.51** | **0.69** | (0.29) | (0.64) | 0.09 | (0.05) |
| Capital expenditures | **$ 19,460** | **$ 25,493** | **$ 21,102** | **$ 36,836** | $ 10,389 | $ 9,337 | $ 16,489 | $ 18,854 |
| Weighted average common shares outstanding | | | | | | | | |
| - basic | **16,224** | **16,224** | **16,216** | **16,068** | 13,354 | 13,348 | 13,349 | 14,743 |
| - diluted * - net income (loss) | **16,224** | **16,404** | **19,781** | **19,766** | 13,354 | 13,348 | 13,523 | 14,743 |
| - cash flow from operations | **19,632** | **19,813** | **19,781** | **19,766** | 16,763 | 16,776 | 16,931 | 18,195 |
| **Common Share Information** | | | | | | | | |
| American Stock Exchange | | | | | | | | |
| Per share - high | **$ 20.38** | **$ 22.25** | **$ 22.50** | **$ 27.75** | $ 15.50 | $ 18.63 | $ 22.75 | $ 20.38 |
| - low | **13.38** | **17.63** | **15.88** | **19.31** | 9.56 | 12.25 | 17.44 | 14.06 |
| - close | **$ 20.13** | **$ 19.06** | **$ 20.69** | **$ 27.63** | $ 12.25 | $ 17.50 | $ 19.00 | $ 17.25 |
| Volume | **2,924** | **2,914** | **3,965** | **4,424** | 3,703 | 2,959 | 1,872 | 5,551 |
| Toronto Stock Exchange | | | | | | | | |
| Per share - high | **C$ 27.85** | **C$ 33.20** | **C$ 33.50** | **C$ 41.90** | C$ 24.00 | C$ 26.95 | C$ 34.00 | C$ 30.25 |
| - low | **19.50** | **25.45** | **23.60** | **29.20** | 14.50 | 19.25 | 25.90 | 21.00 |
| - close | **C$ 27.85** | **C$ 28.60** | **C$ 31.00** | **C$ 41.50** | C$ 18.90 | C$ 25.25 | C$ 27.60 | C$ 25.00 |
| Volume | **483** | **269** | **536** | **599** | 911 | 720 | 413 | 345 |

* Restated to reflect retroactive application of treasury stock method when assessing share options for dilutive effect.

(Unaudited)

## Quarterly Information

| | 2000 Quarter Ended | | | | 1999 Quarter Ended | | | |
|---|---|---|---|---|---|---|---|---|
| | **Mar 31** | **Jun 30** | **Sep 30** | **Dec 31** | Mar 31 | Jun 30 | Sep 30 | Dec 31 |
| **Operating** | | | | | | | | |
| Daily volumes, before royalties | | | | | | | | |
| Natural gas *(mmcf)* | | | | | | | | |
| US | **66.1** | **63.4** | **77.2** | **77.6** | 76.1 | 74.4 | 76.7 | 74.6 |
| UK | **8.5** | **5.9** | **0.3** | **6.5** | 11.0 | 7.7 | 10.5 | 10.1 |
| Total | **74.6** | **69.3** | **77.5** | **84.1** | 87.1 | 82.1 | 87.2 | 84.7 |
| Oil and ngls *(barrels)* | **4,154** | **4,181** | **3,964** | **3,792** | 3,679 | 5,222 | 5,200 | 4,329 |
| Equivalent *(mmcfe)* | **99.5** | **94.3** | **101.3** | **106.8** | 109.2 | 113.4 | 118.4 | 110.7 |
| Daily volumes, after royalties | | | | | | | | |
| Natural gas *(mmcf)* | | | | | | | | |
| US | **52.9** | **51.0** | **62.4** | **62.4** | 60.1 | 59.1 | 61.4 | 59.8 |
| UK | **8.5** | **5.9** | **0.3** | **6.5** | 11.0 | 7.7 | 10.5 | 10.1 |
| Total | **61.4** | **56.9** | **62.7** | **68.9** | 71.1 | 66.8 | 71.9 | 69.9 |
| Oil and ngls *(barrels)* | **3,494** | **3,531** | **3,351** | **3,208** | 3,156 | 4,421 | 4,394 | 3,671 |
| Equivalent *(mmcfe)* | **82.4** | **78.1** | **82.8** | **88.1** | 90.1 | 93.3 | 98.3 | 92.0 |
| Pricing | | | | | | | | |
| Natural gas *($ per mcf)* | | | | | | | | |
| US | **$ 2.51** | **$ 3.18** | **$ 3.84** | **$ 5.20** | $ 1.60 | $ 1.97 | $ 2.46 | $ 2.58 |
| UK | **1.35** | **1.58** | **1.92** | **3.09** | 1.13 | 0.82 | 0.81 | 1.03 |
| Composite | **2.38** | **3.04** | **3.83** | **5.03** | 1.54 | 1.86 | 2.26 | 2.39 |
| Oil and ngls *($ per barrel)* | **$ 24.06** | **$ 26.30** | **$ 30.53** | **$ 30.32** | $ 10.94 | $ 15.17 | $ 19.31 | $ 21.67 |

## SELECTED FINANCIAL AND OPERATING DATA

(Unaudited)

| Year ended December 31, *(in thousands except per share amounts)* | 2000 | 1999 | 1998 | 1997 | 1996 |
|---|---|---|---|---|---|
| **FINANCIAL** | | | | | |
| Production revenue - before royalties | $ 142,391 | $ 91,507 | $ 74,861 | $ 84,219 | $ 72,838 |
| - after royalties | 116,992 | 75,366 | 61,615 | 69,627 | 60,612 |
| Cash flow from operations, after preferred share dividends | 93,631 | 50,098 | 37,847 | 49,473 | 41,841 |
| Per share - basic | 5.79 | 3.66 | 2.81 | 3.63 | 3.20 |
| - diluted * | 4.99 | 3.22 | 2.51 | 3.14 | 2.80 |
| Net income (loss) | 27,348 | (11,839) | (9,055) | 5,218 | 4,842 |
| Per share - basic | 1.69 | (0.86) | (0.67) | 0.38 | 0.37 |
| - diluted * | 1.64 | (0.86) | (0.67) | 0.38 | 0.36 |
| Capital expenditures | 102,891 | 55,069 | 92,666 | 69,777 | 57,860 |
| Long-term debt | 20,000 | 10,000 | 40,000 | – | – |
| Working capital | 9,962 | 13,604 | 2,392 | 22,676 | 42,854 |
| Total assets | 395,460 | 330,758 | 318,584 | 285,125 | 267,442 |
| Shareholders' equity | $ 295,146 | $ 271,101 | $ 234,946 | $ 249,466 | $ 244,122 |
| Weighted average common shares outstanding | | | | | |
| - basic | 16,183 | 13,701 | 13,480 | 13,621 | 13,065 |
| - diluted * - net income (loss) | 19,745 | 13,701 | 13,480 | 13,912 | 13,317 |
| - cash flow from operations | 19,745 | 17,109 | 17,051 | 17,320 | 16,726 |
| **OPERATING** | | | | | |
| Average composite prices | | | | | |
| Natural gas *(mcf)* | $ 3.63 | $ 2.02 | $ 1.99 | $ 2.33 | $ 2.09 |
| Oil and ngls *(barrel)* | $ 27.72 | $ 17.05 | $ 11.74 | $ 18.94 | $ 20.99 |
| Average production rate, before royalties | | | | | |
| Natural gas *(mmcf per day)* | 76.4 | 85.3 | 82.3 | 77.6 | 71.8 |
| Oil and ngls *(barrels per day)* | 4,022 | 4,611 | 3,482 | 2,636 | 2,340 |
| Equivalent *(mmcfe per day)* | 100.5 | 112.9 | 103.2 | 93.4 | 85.8 |
| Proved reserves, before royalties | | | | | |
| Natural gas *(bcf)* | 233.8 | 186.3 | 159.1 | 149.4 | 150.6 |
| Oil and ngls *(mmbbls)* | 15.3 | 17.3 | 15.2 | 13.0 | 10.6 |
| Equivalent *(bcfe)* | 325.8 | 290.3 | 250.4 | 227.5 | 214.0 |
| Present value *(discounted at 10% constant dollars before taxes, in thousands)* | $ 1,226,959 | $ 266,474 | $ 152,508 | $ 238,312 | $ 304,296 |
| Wells drilled | | | | | |
| Gross | 35 | 20 | 49 | 61 | 45 |
| Net | 13.18 | 7.32 | 12.25 | 14.73 | 9.65 |
| Success rate | 63 % | 70 % | 84 % | 84 % | 78 % |

* Restated to reflect retroactive application of treasury stock method when assessing share options for dilutive effect.

# CORPORATE GOVERNANCE

The Board of Directors and management of the Company support the guidelines for corporate governance set forth by the Toronto Stock Exchange and the Company's corporate governance practices were developed in accordance with these guidelines.

## THE BOARD'S MANDATE

The Board of Directors exercises overall responsibility for the management and supervision of the Company's affairs. It has established processes, policies and practices to guide its stewardship of the Company in the areas of strategic planning; identification and management of the principal risks of the Company's business; succession planning and management development; communications; and internal control and management information. Management is responsible for providing information and maintaining processes which enable the Board to discharge its responsibilities. Administrative procedures govern the approval of transactions, the delegation of authority and the signing of documents.

The Board of Directors is kept informed of the Company's operations through regularly scheduled meetings of the Board and its committees and through reports and analyses and discussions with management. During 2000, the Directors met at four regularly scheduled and two additional meetings. Communications between the Directors and management occur as required in addition to the board and committee meetings.

The Board of Directors annually reviews and approves the Company's corporate strategy. The Board reviews the Company's budget for the following fiscal year, including operating and financial targets and approves the capital expenditures for which management is responsible. As part of that process, the objectives of the Chief Executive Officer and the Chief Operating Officer are reviewed.

Management performance, succession planning and management development are regularly reviewed by the Compensation Committee and in turn by the Board of Directors .

The Company's communications strategy and implementation is regularly reviewed by the Board of Directors and the Board is informed of communication activities. In addition to the Annual Meeting, the Company participates in conferences and quarterly conference calls. The Company's transfer agent, CIBC Mellon Trust Company has a toll-free number (1-800-387-0825) to assist shareholders. The Board and appropriate Committees review the Company's Annual Report to Shareholders, Management's Discussion and Analysis, Information Circular, Annual Information Form, Form 10-K Annual Report, quarterly financial statements, Interim Reports, Form 10-Q Reports and news releases on major developments before they are distributed. The Company provides information on its business and financial results on its internet site at www.chieftaininternational.com. News releases and other prescribed documents are available on the electronic databases mandated by the Securities and Exchange Commission known as "EDGAR" (www.sec.gov) and by Canadian Securities Authorities known as "SEDAR" (www.sedar.com).

## THE BOARD'S COMPOSITION

The Board of Directors is comprised of eight members. Having regard to the size and complexity of the Company's business, the Board considers that eight is the minimum number of directors required.

The Board of Directors is constituted with a majority of individuals who are independent, unrelated directors. Three senior officers of the Company are members of the Board. The Chairman of the Board is a non-executive Chairman who has not held another office with the Company. The Board meets at least annually with only the independent, unrelated members in attendance.

## COMMITTEES OF THE BOARD

The Board of Directors has five committees, as follows. Each of the committees has four members and all committees are comprised entirely of independent, unrelated directors. Committees may engage external resources.

### *Audit Committee*

The primary function of the Audit Committee is to assist the Board of Directors in providing corporate oversight in the areas of financial reporting, internal control and the audit process. The Committee regularly meets alone with Company personnel and with the independent auditors. The independent auditors have access to the Committee at any time. The Committee reviews and recommends to the Board for its approval the annual financial statements and is also responsible for reviewing interim unaudited financial statements prior to their release. The Committee reviews and recommends the annual appointment, terms of engagement and proposed fees of the independent auditors.

### *Compensation Committee*

The primary function of the Compensation Committee is to assist the Board of Directors in carrying out its responsibilities by reviewing compensation matters and making recommendations to the Board. It considers and provides recommendations to the Board on Directors' compensation, appointment and remuneration of officers and grants of share options. This Committee reviews compensation and benefits policies, plans and budgets; salaries of certain non-officer employees; results based compensation; and succession planning.

### *Nominating and Corporate Governance Committee*

The Nominating and Corporate Governance Committee assists the Board by reviewing corporate governance and Board nomination matters and making recommendations to the Board as appropriate. The Committee advises the Board on such matters as the size and composition of the Board of Directors and its committees, nominees for the election of directors and corporate governance practices.

### *Pension Committee*

The Pension Committee reviews and makes recommendations to the Board of Directors with regard to the Company's retirement plans, related agreements, the appointment and performance of retirement fund investment managers, and compliance with the plans' statements of investment policies.

### *Reserve Committee*

The primary function of the Reserve Committee is to review the Company's externally disclosed natural gas and oil reserve estimates. The Committee reviews the reports of the independent engineers charged with evaluating the Company's reserves and also reviews the selection and qualifications of the independent engineers, the scope of their work and the evaluation procedures used.

## SHARE INFORMATION

| | 2000 | 1999 | 1998 |
|---|---|---|---|
| **Common Shares - "CID"** | | | |
| Outstanding at December 31 *(in thousands)* | | | |
| Basic | **16,101** | 16,224 | 13,356 |
| Diluted * - income (loss) | **19,663** | 16,224 | 13,356 |
| - cash flow from operations | **19,663** | 19,632 | 16,927 |
| Weighted average *(in thousands)* | | | |
| Basic | **16,183** | 13,701 | 13,480 |
| Diluted * - income (loss) | **19,745** | 13,701 | 13,480 |
| - cash flow from operations | **19,745** | 17,109 | 17,051 |
| Approximate number of registered shareholders at December 31, | **116** | 97 | 107 |
| Estimated number of beneficial holders | **2,200** | 2,150 | 2,200 |
| Trading - American Stock Exchange *(US$ per share except volumes)* | | | |
| High | **27.75** | 22.75 | 24.75 |
| Low | **13.38** | 9.56 | 13.94 |
| Close | **27.63** | 17.25 | 14.38 |
| Volume | **14,226,900** | 14,085,400 | 9,790,000 |
| Trading - Toronto Stock Exchange *(C$ per share except volumes)* | | | |
| High | **41.90** | 34.00 | 35.35 |
| Low | **19.50** | 14.50 | 21.60 |
| Close | **41.50** | 25.00 | 23.05 |
| Volume | **1,887,088** | 2,387,810 | 3,014,000 |
| **Preferred Shares - "GSS.PR"** | | | |
| Outstanding at December 31 | **2,726,700** | 2,726,700 | 2,726,700 |
| Trading - American Stock Exchange *(US$ per share except volumes)* | | | |
| High | **34.75** | 29.88 | 32.50 |
| Low | **21.75** | 20.25 | 22.75 |
| Close | **34.63** | 25.50 | 24.13 |
| Volume | **2,753,600** | 2,324,500 | 3,734,300 |
| Dividends paid *(in thousands)* | $ **4,942** | $ 4,942 | $ 4,942 |

* Restated to reflect retroactive application of treasury stock method when assessing share options for dilutive effect.

# SHAREHOLDER INFORMATION

## COMMON SHARES

### *Listed*

American Stock Exchange
Toronto Stock Exchange
Trading symbol: CID

### *Registrar and Transfer Agent*

CIBC Mellon Trust Company
600, 333 - 7th Avenue SW
Calgary, Alberta T2P 2Z1 Canada

| | |
|---|---|
| Telephone: | (403) 232-2400 |
| Facsimile: | (403) 264-2100 |
| Email: | inquiries@cibcmellon.ca |
| Web site: | www.cibcmellon.ca |
| Answerline: | 1-800-387-0825 |

### *Co-transfer Agent*

Mellon Investor Services LLC
PO Box 3315
South Hackensack, New Jersey 07606 USA

| | |
|---|---|
| Telephone: | 1-800-851-9677 |
| Web site: | www.mellon-investor.com |

### *Dividend Policy*

The Company currently does not pay dividends on the common shares. Cash flow is utilized to support operations, exploration and development programs.

## PREFERRED SHARES

### *Listed*

American Stock Exchange
Trading symbol: GSS.PR

### *Registrar and Transfer Agent*

Mellon Investor Services LLC
PO Box 3315
South Hackensack, New Jersey 07606 USA

| | |
|---|---|
| Telephone: | 1-800-851-9677 |
| Web site: | www.mellon-investor.com |

### *Dividend Policy*

Chieftain International Funding Corp., a wholly-owned subsidiary of Chieftain International, Inc., pays regular quarterly dividends at the annual rate of $1.8125 per preferred share.

## FORM 10-K ANNUAL REPORT AND ANNUAL INFORMATION FORM

**Copies of the Company's latest Form 10-K Annual Report as filed with the Securities and Exchange Commission and Annual Information Form as filed with securities commissions in Canada are available upon request to the Secretary of the Company.**

## INVESTOR RELATIONS

Shareholders are welcome to contact the Company for general information or questions concerning their shares.

| | |
|---|---|
| Contact: | Randall P. Boyd<br>Vice President, Investor Relations |
| Telephone: | (780) 425-1950 |
| Facsimile: | (780) 429-4681 |
| Email: | chieftain@chieftaininternational.com |

## ANNUAL MEETING

The Annual Meeting of Shareholders will be held on Thursday, May 17, 2001 at 10:30 a.m. in the Marlboro Room, The Westin Hotel, Edmonton, Alberta, Canada.

## INTERNET

Investors are invited to visit our internet site for further information including recent press releases, investor presentations, interim and annual reports.

Web site: www.chieftaininternational.com

**CHIEFTAIN**
INTERNATIONAL, INC.


Telephone: (780) 425-1950
Fax: (780) 429-4681
Email: chieftain@chieftaininternational.com
Web site: www.chieftaininternational.com


*(Please print legibly)*

Name: ______________________

Title: ______________________

Company: ______________________

Address: ______________________

______________________

______________________

Telephone: ______________________

Fax: ______________________

Email: ______________________

Please check the appropriate boxes and return this card by mail or fax.

**Shareholder** ☐ Yes ☐ No

Mailing list request:

| **Add my name** Mail | Fax | Email | | **Remove my name** |
|---|---|---|---|---|
| ☐ | n/a | n/a | **Annual Report** | ☐ |
| ☐ | n/a | n/a | **Interim Reports** | ☐ |
| ☐ | ☐ | ☐ | **News Releases** | ☐ |
| ☐ | n/a | n/a | **AIF** | ☐ |
| ☐ | n/a | n/a | **10-K Report** | ☐ |
| ☐ | n/a | n/a | **10-Q Reports** | ☐ |
| ☐ | n/a | n/a | **Information Kit** | ☐ |

For further information, please contact Susan Angus (780) 425-1950.

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Corporate Director and
Financial Consultant
Dallas, Texas

**Esther S. Ondrack**

Senior Vice President and Secretary,
Chieftain International, Inc.
Edmonton, Alberta

**Stuart T. Peeler** (1) (2*) (3) (4) (5)

Corporate Director and
Petroleum Industry Consultant
Tucson, Arizona

*Committee Membership (* Chair)*
*(1) Audit Committee*
*(2) Compensation Committee*
*(3) Nominating and Corporate Governance Committee*
*(4) Pension Committee*
*(5) Reserve Committee*

## AUDITORS

PricewaterhouseCoopers LLP
Edmonton, Alberta

## LEGAL COUNSEL

Bennett Jones
Calgary, Alberta

Cravath, Swaine & Moore
New York, New York

John L. Roach, Inc.
Dallas, Texas

LeBoeuf, Lamb, Greene & MacRae
London, England

## PETROLEUM ENGINEERS

Netherland, Sewell & Associates, Inc.
Dallas, Texas

## BANK

Canadian Imperial Bank of Commerce
Calgary, Alberta

## WHOLLY-OWNED SUBSIDIARIES

Chieftain International (U.S.) Inc.
Chieftain International Funding Corp.
Chieftain Exploration (UK) Limited
Chieftain International North Sea Limited

**Abbreviations**

| | |
|---|---|
| b | billion |
| bbl | barrel |
| bcfe | 1 million barrels of oil = 6 bcf of natural gas |
| C$ | Canadian currency |
| cf | cubic feet |
| e | equivalent |
| m | thousand |
| mm | million |
| ngls | natural gas liquids |

CHIEFTAIN
INTERNATIONAL, INC.


**CORPORATE OFFICE**

Chieftain International, Inc.
1201 TD Tower
10088 - 102 Avenue
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Email: chieftain@chieftaininternational.com
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